Reasonable Foreseeable Development Roan Plateau Planning Area

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List of Abbreviations

AU ... Assessment Unit
BCF ... One Billion Standard Cubic Feet of Gas
BLM ... Bureau of Land Management
CA ... Communitization Agreement
CBNG ... Coalbed Natural Gas
COGCC ... Colorado Oil and Gas Conservation Commission
CRVFO ... Colorado River Valley Field Office
DOE ... Department of Energy
EIA ... United States Energy Information Administration
EIS ... Environmental Impact Statement
EPCA ... Energy Policy and Conservation Act
EUR ... Estimated Ultimate Recovery
FAN ... Final Abandonment Notice
GJFO ... Grand Junction Field Office
MCF ... One Thousand Standard Cubic Feet of Gas
mD ... Millidarcy
MMBTU ... One Million British Thermal Units
MMCF ... One Million Standard Cubic Feet of Gas
MWX ... Multiple Well Experiment
NGL ... Natural Gas Liquids
NOSR ... Naval Oil Shale Reserves
NSO ... No Surface Occupancy
NYMEX ... New York Mercantile Exchange
RFD ... Reasonable Foreseeable Development Scenario
RMPA ... Resource Management Plan Amendment
SCF ... One Standard Cubic Foot of Gas
SEIS ... Supplemental Environmental Impact Statement
TCF ... One Trillion Standard Cubic Feet of Gas
TPS ... Total Petroleum System
USFS ... United States Forest Service
USGS ... United States Geological Survey
WRFO ... White River Field Office

Summary

This Reasonable Foreseeable Development Scenario (RFD) was prepared to support the Resource Management Plan Amendment (RMPA) and Supplemental Environmental Impact Statement (SEIS) for the Roan Plateau Planning Area (RPPA) of the Colorado River Valley Field Office (CRVFO), Colorado. It provides the interdisciplinary planning team with an estimate of the oil and gas development activities that are reasonably likely to occur on BLM-administered lands within the RPPA over the next 20 years.

The RPPA is in the southern part of the Piceance Basin, which is part of the greater geologic basin known as the Uinta-Piceance Basin. Current development is focused on the Mesaverde Formation. There currently are 2,661 wells in the RPPA, and oil and gas activities have switched from exploration to developmental. Little development has occurred on top of the plateau, but development below its rim (top of the cliffs) has been extensive, and approximately 50% of the acreage available for development has been developed.

The Bureau of Land Management (BLM) Energy Office staff at the CRVFO compiled data from various sources including historical oil and gas development trends and natural gas prices to estimate future development for the RPPA. The CRVFO estimates that 17.1 trillion cubic feet of gas (TCF) is technically recoverable from the Mesaverde Formation in the RPPA. Over the next 20 years, it is projected that 5,470 federal and fee wells could be drilled into the RPPA, with 1,070 federal wells on top of the plateau and 2,450 federal wells below the rim, see Table 3. This development is estimated to create an additional 5,928 aces of net disturbance, including 1,898 acres on federal lands.

Background

The development of the initial Roan Plateau RMP Amendment began with scoping in 2000. The Draft Environmental Impact Statement (EIS) was published in November 2004. The Final EIS was published in August 2006. The BLM then issued two Records of Decision, one in June 2007 and a second, pertaining to Areas of Critical Environmental Concern, in March 2008. A lawsuit filed in July 2008 that challenged the BLM's oil and gas leasing and management decisions for the Roan Plateau resulted in a June 22, 2012, ruling by the United States District Court for the District of Colorado. The Court set aside the Plan amendment and remanded the matter to the BLM for further action in accordance with the Court's decision.

In response to the Opinion and Order of the United States District Court for the District of Colorado on June 22, 2012, the RMPA/SEIS for the RPPA is being prepared. A Notice of Intent to initiate scoping for the SEIS was published to the Federal Register on January 28, 2013. The RMPA/SEIS will analyze options for future management of the RPPA consistent with the 2012 Court Order. It will also address significant new information arising since publication of the original Records of Decision (RODs) in August 2007 and March 2008 and issues identified by the scoping process.

Reconsideration of oil and gas development was a component of the Court Order and an issue identified during scoping; therefore, the BLM has concluded that it is appropriate to update the RFD prepared November 2005 for the RPPA in conjunction with the earlier 2006 RMPA/EIS.

A RFD is a long-term scenario used as a baseline for adjusting the projected amount of oil and gas activity for each alternative in the Draft Resource Management Plan. It is not a decision and does not authorize or approve any development. It is a rational estimate of development based under the assumption that all potential productive areas are open for oil and gas leasing and developed under standard lease terms and conditions, except those areas designated as closed to leasing by law, regulation, or executive order. The RFD estimates the potential oil and gas activity on all lands, including private and state lands. The BLM only has jurisdiction over the activity on federal surface or federal minerals.

This RFD is intended for input into the RMPA/SEIS by:

- Describing the potential level of fluid mineral exploration and production to occur over the next 20 years and estimating the surface disturbance associated with that activity. This information will provide the planning team the basis for assessing the impacts to other resources within the RPPA. The analysis of impacts and associated mitigation measures will be described in the RMPA/SEIS and other National Environmental Policy Act (NEPA) documents.
- Providing a description of past and present exploration and development activities in the RPPA.
- Discussing ancillary facilities and surface impacts from past and current activity.
- Analyzing the geology, technologies, and methodologies that occur within the CRVFO in order to support assumptions and projections for the RFD.

The RFD was prepared in accordance with Instruction Memorandum No. 2004-089; subject “Policy for Reasonable Foreseeable Development (RFD) Scenario for Oil and Gas,” dated January 16, 2004.

Description of Geology

Geologic Setting

The Piceance Basin is an elongated northwest-southeast trending structural basin about 100 miles long and 40 to 50 miles wide located in northwestern Colorado. The basin is bounded by the Grand Hogback monocline and the White River Uplift to the east, the Axial Basin Arch to the north, the Douglas Creek Arch to the west, and the Uncompahgre and Sawatch uplifts to the south. The general stratigraphy of the Piceance Basin ranges from Cambrian to Tertiary in age.

During the Cretaceous period 145 to 65.5 million years ago (Mya), the Piceance Basin region was situated on the on the western foreland margin of the Western Interior Seaway, which extended from the Gulf of Mexico to Canada. During Turonian through Campanian time, sediment was shed from the Sevier thrust belt in central Utah and southwestern Wyoming, transported eastward in fluvial depositional systems, and ultimately deposited in shoreline environments that rimmed the epeiric (inland) seaway. Costal-plain swamps developed landward of the Cretaceous shorelines that later formed the prolific coal-bearing successions of the Cameo coal and overlying coal intervals of the Williams Fork Formation. Regression of the seaway resulted in a general eastward progradation of the shorelines and concomitant eastward migration of the coal-bearing deposits.

During this time, several thousand feet of subsidence and accumulation of continental and marginal-marine sediment occurred. At the close of the Cretaceous, Laramide uplifts in the Sawatch Uncompahgre, Douglas Creek, and Uinta regions began to rise as is evident by either regionally extensive unconformities or thinning of the deposits over the incipient uplifts. The Laramide orogeny intensified during the Paleocene and continued throughout the Eocene, resulting in deposition of coarser-grained clastic detritus proximal to the uplifts and accumulation of finer-grained sediment in the intermountain basins.

A wide spectrum of local lithostratigraphic terms are used for facies-equivalent, correlative units of the Piceance Basin. For example, regression of the Western Interior Seaway during Late Campanian time is expressed as high stand progradational parasequence sets that constitute the Corcoran, Cozzette, and Rollins Members of the Mount Garfield Formation in the Book Cliffs area and the Iles Formation in the

Grand Hogback area. The overlying succession of fluvial strata is referred to as the Hunter Canyon Formation of the Mesaverde Group in the Book Cliffs area and the Williams Fork Formation in the Grand Hogback area. These fluvial deposits are succeeded by a 50- to 150-foot-thick interval of coarse-grained sandstone to conglomerate that, in some localities, possess a distinctive white appearance and are overlain by the brightly variegated Eocene Wasatch Formation. This coarse-grained interval has been referred to as the Ohio Creek Conglomerate and the Ohio Creek Member of the Mesaverde Group (Patterson, Kronmueller and Davies).

USGS Oil and Gas Assessment Units

When discussing geology, plays, assessment units (AU), and total petroleum systems (TPS) within the RPPA, it is necessary to include basin wide information. The majority of kerogen rich source rocks and gas bearing formations are contiguous throughout the basin, with the exception of transition zones and basin structural boundaries (i.e. the Grand Hogback, Douglas Arch, and the White River uplift.) The basin-centric nature of the RPPA's geographic and geophysical location means that it overlies all the hydrocarbon bearing formations that are prolific in other fields within the greater CRVFO planning area. Therefore, this document draws heavily from the RFD developed for the CRVFO's RMP.

An oil and gas "play" is a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play may or may not differ from an AU, and an AU can include one or more plays. Conventional plays are plays associated with structural or stratigraphic traps, commonly bounded by a down-dip water contact, and therefore affected by the buoyancy of petroleum in water. Unconventional plays have the following characteristics: (1) are generally very large accumulations occupying the more central, deeper parts of basins; (2) have an absence of down-dip water contacts; (3) are abnormally over- or under-pressured; (4) contain gas that is in the pressuring phase; (5) produce little or no water; (6) have a permeability of less than 0.1 millidarcy (mD); (7) are overlain by a normally pressured transition zone containing gas and water; (8) contain thermogenic gas; (9) have a source of gas that is local—typically from either interbedded or adjacent lithologies; (10) have a 0.75 to 0.9 percent vitrinite reflectance at the top of accumulations; (11) consist only secondarily in structural and stratigraphic traps and; (12) are "sealed" by the presence of multiple fluid phases in low-permeability reservoirs. The U.S. Geological Survey (USGS) has prepared a schematic, shown in Figure 1, illustrating the different types of oil and gas resources.

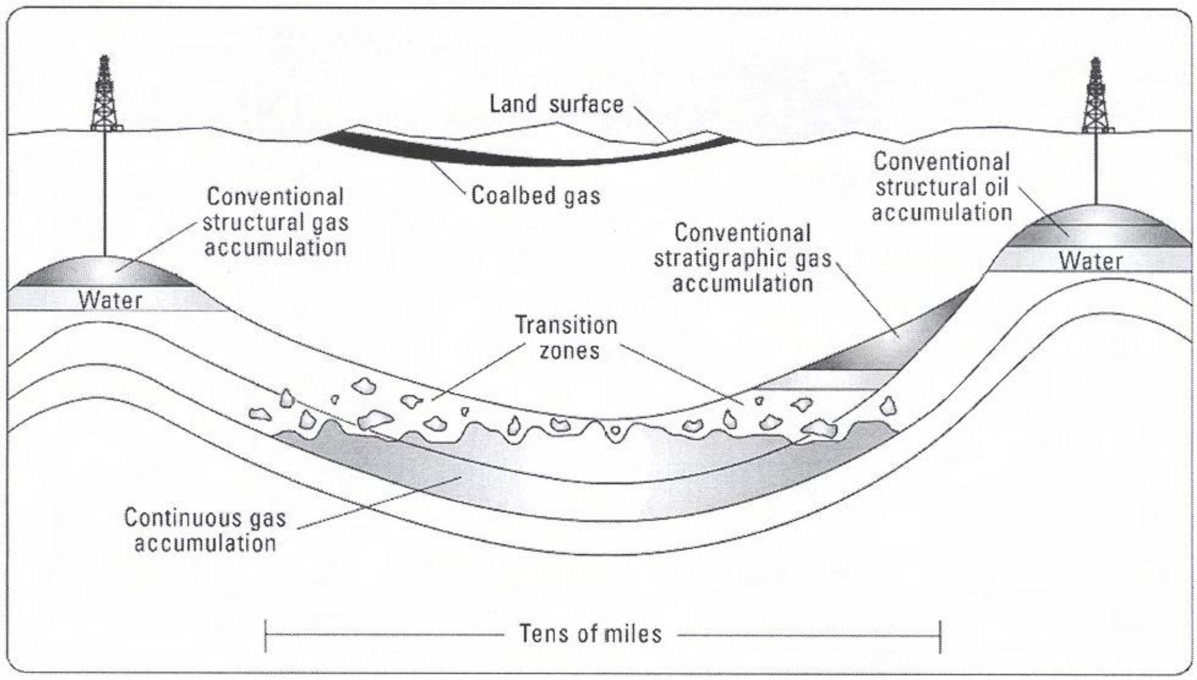

Figure 1. Schematic diagram showing the types of oil and gas resources in USGS assessment.

For the purposes of this RFD, a homogeneous distribution of resources within a play boundary is assumed because of the lack of more geologically specific information. However, gas resources are generally not distributed homogeneously within a play. This is particularly true for conventional accumulations but less so for continuous accumulations. Despite the assumption of homogeneity, various oil and gas densities can be mapped due to play stacking. Following is a discussion of the plays with AU and TPS that pertain to the Piceance Basin.

Piceance Tertiary Conventional Play

This play includes conventional sandstone reservoirs in the Tertiary Green River and Wasatch Formations. This play is included in the Piceance Green River Conventional Oil and Gas AU, located in the extreme western part of the CRVFO. Gas from the Green River Formation is considered to be sourced from the Green River TPS, and gas produced from the Wasatch Formation is considered to be sourced from the Mesaverde TPS. Approximately 11% of the mapped AU is actually mapped within the CRVFO boundary, mostly within the RPPA. In the Piceance Basin, the Green River Formation overlies and inter-fingers with the Wasatch Formation and was deposited in lacustrine environments of the Eocene Lake Uinta. The Green River Formation near the center of the basin is more than 5,000 feet thick. Most of the gas produced from this formation, originating from marginal lacustrine (lake-deposited) rocks or basal transgressive (marine) beds, has been produced in the central part of the basin. Source rocks appear to be from the underlying Mesaverde Group and from organic rocks within the Green River Formation itself. Traps are primarily stratigraphic and structural-stratigraphic. Seals are enclosing shale, mudstone, and siltstone.

Gas produced from the Wasatch Formation is sourced from the underlying Mesaverde Group also. Some oil production also occurs from the Green River Formation, despite the low maturity of the lacustrine source rocks there. Although there are producing wells, the fields are small. This play has been only moderately explored despite being penetrated by numerous wells drilled to Mesaverde objectives. The

Tertiary gas reservoirs are under-pressured, mostly fluvial sandstone, and many of these shallow gas reservoirs may have been bypassed. Due to the higher Mesaverde gas-per-well recoveries, these wells are completed first in the Mesaverde and, after depletion, possibly recompleted in the Wasatch Formation. Green River Formation produces minimal oil or gas within the RPPA. Gas production from the Wasatch Formation, mostly the G Sand, can be found in nearly 200 wells, most of which are located within or near the mapped AU boundary. The USGS expects that 12 more nonassociated gas accumulations will be found within this AU and that a maximum of 65 such accumulations may exist. Within the CRVFO, it is expected that one more field will be discovered, and a maximum of seven fields may exist.

Mesaverde Continuous Gas AU

This AU is defined as that area of the Piceance Basin where a basin-centered continuous gas accumulation developed from the generation and predominantly vertical migration of gas from thermally mature coal and carbonaceous shale source rocks in the lower part of the Mesaverde Group. The boundary of the assessment unit is defined solely by the isoreflectance line being Ro=1.10 percent (Ro = vitrinite reflectance in oil). Stratigraphically, the AU extends vertically from the base of the Cameo coal zone in the Mesaverde Group (Williams Fork Formation) to the base of the Green River Formation. Fluvial channel sandstones in the Mesaverde Group and Wasatch Formation are the primary gas reservoirs. Gas accumulations are sealed by relatively impermeable mud-rock that surrounds many of the sandstone units and by the process of capillary seal within the basin-centered accumulation (Dickinson, and Law). Much of the established production is from fields within valleys cut by the Colorado River and its tributaries. Unloading of overburden because of this down cutting and erosion may have increased permeability by opening up pore throats and fractures (Dickinson, and Law).

Gas production from fields, in this AU, within the CRVFO is primarily from the Williams Fork Formation at total depths ranging from 6,000 to 9,000 feet. Initial production in new wells using modern hydraulic fracturing techniques ranges from 800 one thousand cubic feet (MCF) of gas per day to 1,400 MCF/day on 10-acre spacing. Mesaverde wells usually produce a minor amount of condensate and the USGS determined that average amount to be about 4,324 barrels per well over the life of the well. Only small amounts of water are produced with the gas. Gas is trapped in a 1,700- to 2,400-foot interval of stacked, very low permeability, highly discontinuous fluvial sandstones that are part of a large, basin-centered gas accumulation where the lower two-thirds of the Williams Fork Formation is continuously gas-saturated down dip of water-bearing sandstones.

A widespread, thin shale interval in the upper part of the Williams Fork may have been important as a top seal for overpressuring of the basin-centered gas accumulation. This interval ties closely with a seismic reflector that can be correlated over much of the Piceance Basin. Outcrop and subsurface studies indicate that the typical size of the Williams Fork sandstone reservoirs is small, with typical lateral extents of 500 to 800 feet. In general, the small size of these sandstones is the result of deposition as point bars by meandering streams. Seismic data and well control indicate early movement of Laramide structures. This movement has effected deposition of the Iles and Williams Fork strata.

Many attempts to produce this vast basin-centered resource were unsuccessful until modern hydraulic-fracturing technology made it possible to produce wells at economic rates. Natural fracturing is the primary control of well productivity, and 3D seismic can be used to identify structurally favorable areas. A combination of natural fractures and man-made factures is what makes this play economic. Areas within the Mesaverde Continuous Gas AU that contain gas resources but have little natural fracturing may not be economic to produce even with current hydraulic fracturing techniques. The low permeability and highly lenticular nature of the fluvial sandstones require 20-acre or denser well spacing to drain the Williams Fork reservoir (Cumella and Ostby).

Wasatch reserves are second in size only to the Mesaverde reserves. The Wasatch Formation consists of multiple, lenticular, sandstone lenses interbedded with bentonitic, varicolored shales and siltstones. The sands of the Wasatch were deposited as channels cut into the shales and siltstones. The sands, which usually contain high clay content, are considered tight with low permeability. Most of the Wasatch production is expected to be derived from stratigraphic traps in the G Sand of the Molina Member. Production has been established in the G Sand in several fields within the CRVFO. Much like the Williams Fork, the best production from the Wasatch is dependent on natural fractures as well as induced fracturing. In this area, the Wasatch has been developed at depths between 2,000 and 3,000 feet, with initial well productions of 200 to 300 MCF/day on 160-acre spacing. The Wasatch wells do not produce condensate

It is likely that reserves growth will be experienced within most of the fields portions of in this AU within the CRVFO from improved drilling and completion techniques and from additional infill drilling. Expansion of existing fields will also occur with drilling in untested areas that have geologic characteristics similar to those in the existing fields. New fields may be discovered as a result of new drilling and completion techniques in untested areas. These areas may or may not have the significant natural fracturing that is critical to economic production today. Future fracturing techniques may be able to unlock gas even in areas without significant natural fractures.

Mesaverde Transitional Gas AU

This AU surrounds the Mesaverde Continuous Gas AU and is defined as the area in the Piceance Basin where strata in the Mesaverde TPS include and overlie source rocks in the lower part of the Mesaverde Group, with Ro values between 0.75 percent and 1.10 percent. The AU extends stratigraphically from the base of the Cameo coal to the base of the first significant lacustrine shale in the Green River Formation. Gas accumulations are thought to result primarily from vertical migration of gas from underlying thermally mature coal and carbonaceous shale. Gas saturation is probably less complete than in the Mesaverde Continuous Gas AU because some of the source rocks high in the Mesaverde units are less mature. Consequently, a higher percentage of water-saturated sandstone reservoirs are anticipated in this AU. Reservoir pressures vary from being moderately overpressured in the lower part of the AU to being normally pressured or under pressured in the upper part. Some of the gas-charged reservoirs may have conventional permeability (>0.1 mD) as well as gas-water contacts, particularly in upper stratigraphic intervals of the Mesaverde TPS.

Within the CRVFO, much of the gas production is from the Divide Creek and Parachute fields. Most production is from fluvial channel sandstones in the Mesaverde Group Formations, with lesser production from fluvial channel reservoirs in the Wasatch Formation. Because this AU overlies thermally mature source rocks, gas can be found throughout the entire extent of the AU. However, the number of fields to be discovered could be limited in number and size because of incomplete gas saturation and the increased chance of penetrating water-wet reservoirs. Future fields may be best found in areas where structures can enhance gas migration and accumulation. The USGS predicts that additional reserves in the next 20 years will be found primarily in existing fields.

Mesaverde Group Coalbed Natural Gas AU

This AU represents areas where the Williams Fork Formation in the Piceance Basin contains significant coalbeds at depths estimated to be 7,000 feet or less. The depth cutoff was extended to 7,000 feet in the Piceance Basin in order to include all coalbed natural gas production (CBNG) in the Grand Valley and Parachute fields. The top of the Rollins Sandstone Member of the Iles Formation, which marks the base of the Cameo coal group in the lower part of the Mesaverde Group, was used to define the location of the 7,000-foot depth cutoff. More than 5,000 feet of erosion and down cutting in the Colorado River drainage in the Piceance Basin has decreased the drilling depths to higher rank (more thermally mature) coalbeds.

Thermally mature coal in the Williams Fork Formation is present in a belt as much as 10 miles wide along the southwestern margin of the Piceance Basin and in an area as much as 7 miles wide on the northeastern flank of the Divide Creek Anticline. Unfortunately, much of the coal has low permeability.

Total net coal thickness in the Cameo coal group varies from near zero in the extreme southeastern part of the Piceance Basin to greater than 180 feet in the northeastern corner. Throughout most of the basin, however, the zone contains from 20 to 80 feet of total net coal; in the southwestern part of the basin, total net coal thickness near the Utah-Colorado border decreases to less than 20 feet (Kirschbaum and Hettinger). Coalbed gas content is approximately 600 standard cubic feet per ton (SCF/ton) at depths of 7,000 feet and may be as high as 765 SCF/ton at 7,100 foot depths (Johnson and Rice).

Coalbed natural gas wells have been drilled within the CRVFO. Wells completed in the Cameo coals within the Great Divide field have high water production. Individual wells have reported as much as 3 million barrels of water produced within a 6-year period while producing 1,200 MCF/day. Water within the Great Divide field averages around 9,000 milligrams per liter (mg/L) of total dissolved solids (TDS). This does not meet State surface discharge standards and, as a result, injection of the water into the deeper Cozzette Sandstone is being considered. Analysis of the Cameo coals, in areas where coalbed natural gas is considered viable, show excellent gas saturation.

Many wells today have production from the Cameo coal zone commingled with production from adjacent sandstones. This is evident in the Parachute and Grand Valley fields. According to PI Dwights Production Data, the Parachute field has more than 700 wells of which 29 are classified as CBNG wells. The same database show the Grand Valley field with more than 1000 producing wells and 40 of these wells being classified as CBNG wells. The perforation zones range from 200 to more than 500 feet, which is much thicker than the coals zones and encompasses many gas sands as well.

Because of the lack of progress in solving the problems in producing commercial quantities of coalbed gas in the Mesaverde Coalbed Gas AU during the past, it is difficult to estimate how much of the included area has potential for additions to reserves over the next 20 years. This AU is largely untested but has the potential for new discoveries of coalbed gas. In the future, coalbed gas production may result largely from recompleting existing gas wells after depletion of the gas resource in associated sandstone reservoirs. Recompletion in existing wells is far cheaper than drilling new wells and may make coalbed gas economically viable. Additional sweet spots may be found in untested areas that will augment coalbed gas production from recompleted wells in established fields, and new advanced recovery techniques could increase the productivity, especially in areas of thick coal accumulation. If disposal of produced water becomes successful and economical, then increased interest in future coalbed gas exploration and drilling will occur. Currently, operators in the area have been experimenting with water quality improvement processes. If successful in the future, these may lead to acceptable surface discharge scenarios that may be more economical than underground injection.

Mancos/Mowry Continuous Gas AU

This AU includes three groups of reservoirs: (1) a lower group consisting of units in the Morrison Formation (including Salt Wash and Brushy Basin Members), and Dakota Sandstone; (2) a middle group consisting of units in the Frontier Formation, Mancos Shale, and Mancos B; and (3) an upper group consisting of units in the Sego Sandstone, Morapos Sandstone Member, and sandstones of the Iles Formation or equivalents (Corcoran, Cozzette, and Rollins Sandstone Members), all within the Mancos/Mowry TPS. Reservoirs in this AU are usually tight and may be overpressured. Production is dependent on fracture permeability. Locally non-associated gas is produced from the Cozzette, Corcoran, and Dakota Sandstones and in two Morrison Formation wells within the Shire Gulch field located just west of the CRVFO boundary. Several wells with some Mancos production are also present in the Grand Valley and Rulison fields.

The total area that has potential for additions to reserves in the next 20 years is most likely in areas of current production and mostly limited to the lower (Morrison and Dakota) and upper (Iles sandstones) reservoir groups. The best potential comes from (1) isolated sweet spots in the Rulison, Divide Creek, Baldy Creek, Grand Valley, and Mamm Creek fields; (2) areas where there are porous and permeable sandstones in the Morrison and Dakota; and (3) infill drilling and recompletions from the upper group of reservoirs of the Iles and its equivalents. New fields developing resources within this AU are likely.

Plays Identified by Industry

The plays discussed below are the Industry submissions and do not represent all potential plays within the CRVFO. Many of the operators/lessees with interests in the CRVFO were not part of this process. Some declined invitations to participate. As a result, not all current and future plays are discussed here. Some of the USGS plays discussed above are also discussed here because they are the plays most likely to be explored and developed.

Mesaverde Gas Play

Most of the major oil and gas operators in the CRVFO area are interested in this play, which includes all production from the Mesaverde Group, including the Corcoran, Cozzette, and Rollins Sandstone Members of the Iles Formation and the Williams Fork Formation. The latter includes the Cameo coal zone. The large majority of the oil and gas reserves within the RPPA are associated with this play, which extends across the entire area. It is assumed that this play will continue to be developed on 10-acre spacing using multi-well pads.

Wasatch Gas Play

This play is second in reserves only to the Mesaverde play. Most of the production is expected to be from the G Sand of the Molina Member. Infill drilling will continue in the sweet spots such as the Rulison, Parachute, and Grand Valley fields. Much of the future production will be from existing wellbores through recompletions when the Mesaverde gas is depleted. New drilling will also occur outside the established production areas and spacing is assumed to be at 160 acres. The number of wells to be drilled specifically to exploit the Wasatch has not been identified by Industry, but some of the projected wells for the Mesaverde Gas Play will have multiple completions in the Mesaverde and Wasatch.

Niobrara Gas Play

Five Niobrara wells are currently producing within the RPPA boundary. The Niobrara is ultimately a small member within the larger Mancos marine shale. This play is mostly for gas. It is hoped that the Niobrara has significant natural fracturing within the indurated shales that will act as secondary, not primary, porosity. Ultimate spacing has not been determined at this time.

Past and Present Oil and Gas Exploration Activity

Although it has been known for decades that the Williams Fork Formation contains significant gas resources, very low permeability of the sandstones made it difficult to complete wells that would produce at economic rates. With the advent of advanced completion techniques, true dry holes are now rare. For the most part, the lower two thirds of the Williams Fork is gas saturated.

Production from the Williams Fork was established in the Rulison field in the 1960s, and repeatable commercial production from the Williams Fork first occurred in the mid-1980s. The Grand Valley field was discovered in 1984. In 1981, the Department of Energy (DOE) performed a multi-well experiment in the Rulison field. This experiment involved three wells being drilled on a tight pattern of 100 to 200 feet of each other. A horizontal DOE well was also drilled in the same section in the Cozzette Member of the

Iles Formation. These experiments have greatly expanded the knowledge about the tight gas sand reservoirs within the southern Piceance Basin. Better completions as a result of this knowledge have increased estimated ultimate recoveries (EUR) of previously drilled wells in this area from as little as 0.15 billion cubic feet (BCF) to wells drilled in 1994 that have maximum EURs of 1.9 BCF.

Further experimentation by operators drilling and producing from the Williams Fork Formation has shown field growth reserves can be expanded considerably by drilling on 10-acre spacing. This spacing has been proven effective in draining a vast majority of the reservoir that was not occurring at greater spacing intervals. This tight spacing coupled with improved completion techniques has led to the expansion of existing fields and the development of new fields producing from the Williams Fork Formation.

Other new fields being developed today involve coalbed natural gas from the Cameo coal zone such as is present in the Divide Creek field. The Cameo coals' gas content exceeds 750 SCF/ton and was classified as world class. These coals produce a lot of marginally fresh water. If the produced water can be disposed in an economical way, new fields in areas of known Cameo coal gas reserves will also be developed.

Presently the Niobrara Formation is being drilled with hopes of producing natural-fracture gas reservoirs. These fractures are a result of the indurated shales being stretched and folded over the point of greatest flexure on anticlinal fold axis. The fractures act as the primary porosity for the gas, and the reservoir is sealed by a more fissile shale layer above.

Past and Present Oil and Gas Development Activity

Leasing Activity

The BLM issues two types of leases for oil and gas exploration and development on lands owned or controlled by the Federal Government: competitive and noncompetitive. Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases can only be issued after the lands have been offered competitively at an oral auction and not received a bid. The maximum competitive lease size is 2,560 acres in the lower 48 States and 5,760 acres in Alaska. The maximum noncompetitive lease size in all States is 10,240 acres. Since passage of the Energy Policy Act of 1992, both competitive and noncompetitive leases are issued for a 10-year period. Both types of leases continue for as long thereafter as oil or gas is produced in paying quantities.

Currently almost all of the BLM Federal mineral estate is leased as seen in Figure 23 on page 44. The total acres of BLM mineral estate is 73,730 acres. Approximately, 54,630 acres of the leases in the RPPA are suspended due to ongoing litigation. These leases will be analyzed under the BLM's SEIS. Lands remaining available to be leased include approximately 3,540 acres. Most of the unleased land is located in the northeastern corner of the RPPA. No United State Forest Service (USFS) or Colorado State mineral estate is located within the RPPA boundary. The majority of the federal minerals are below federal surface as seen in Figure 22 on page 43. Only 9.4% of the federal mineral acreage is split estate (private surface underlain by federal mineral estate). The total private mineral estate is 53,270 acres. The different acreages are summarized in

Table 1.

Table 1. Current leasing in the RPPA.

Mineral Ownership	Total Mineral Estate (acres)	Leased Lands (acres)	Lands Available for Lease (acres)
BLM (split estate)	6,950	6,140	910
BLM (surface & mineral)	66,780	64,160	2,630
BLM (total)	73,730	70,300	3,540
Fee	53,270	-	-

Unit Agreements

The objective of unitization is to proceed with a program that will adequately and timely explore and develop all committed lands within the unit area without regard to internal ownership boundaries. Exploratory units normally embrace a prospective area that has been delineated based on geological and/or geophysical inference. Exploratory unit agreements normally encompass all oil and gas interests in all formations within the unit area and provide for the allocation of unitized production to the committed lands that have been reasonably proven productive of unitized substances in paying quantities on the basis of the surface acreage included within the controlling participating area. By effectively eliminating internal property boundaries within the unit area, unitization permits the most efficient and cost-effective means of developing the underlying oil and gas resources.

The BLM approves a unit agreement when appropriate in the interest of conserving the natural resources and when it is determined to be necessary or advisable in the public interest. When such a determination is made and lands are committed to the unit, the BLM has a responsibility to ensure that unit development proceeds in a way that continues to serve the public interest, regardless of whether the Federal lands comprise only a small fraction or a major part of the unit area. Currently, the RPPA does not contain a unit agreement.

Communitization Agreements

When a lease or a portion thereof cannot be independently developed and operated in conformity with an established well spacing or well development program, the BLM may approve drilling agreements or communitization of such lands with other lands, upon a determination that it is in the public interest.

Communitization is widely used within the RPPA. Currently 87 Communitization agreements (CA) involving approximately 23,080 acres are in effect. The physical acreage is smaller than the total CA acreage. Since CAs are formation specific, there can be multiple CAs at the same location. Refer to Figure 24 on page 45 for a plat of the existing CAs in the RPPA. Currently, 42 of the CAs in the RPPA communitize gas production from the Mesaverde, 14 CAs in the RPPA communitize production from the Williams Fork Formation, and 31 CAs in the RPPA communitize production from the Wasatch Formation.

Spacing Requirements

The current State of Colorado spacing requirement is 40 acres (600-foot setbacks from the lease line) for wells greater than 2,500 feet in depth, but this spacing can be increased or decreased depending on geology and reservoir characteristics and has been greatly modified in the Piceance Basin. The Colorado Oil and Gas Conservation Commission (COGCC) use the term “default spacing” with modification occurring through Cause Orders. These adjustments are meant to maximize production of the resource while minimizing surface disturbance and expense. In the case involving production from the Williams Fork Formation, 10-acre spacing has been justified and approved. Currently, the Wasatch Formation is being drained on 160-acre spacing in selected areas. New spacing regulations may be necessary to accommodate new drilling and production techniques in the RPPA. Future production from previously undeveloped plays such as the Niobrara play in the Mancos Formation may also require spacing changes. Tight sands, compartmental geology, and reservoir characteristics may increase the demand for tighter spacing in the future in reservoirs other than the Williams Fork Formation.

Drilling and Completion Statistics

The current drilling and production within the RPPA exists in the Southern and Western areas below the rim of the Roan Plateau. The current surface hole locations for all the wells in the RPPA are shown in Figure 23 on page 44.

As of September 2013, there are approximately 2,800 wells within the RPPA based on surface hole location. Well data was pulled from the COGCC's public database and IHS Enerdeq, a private company's database for global energy data and information. According to IHS Enerdeq, there are 2,766 active wells in the RPPA and according to COGCC data there are 2,661 active wells in the RPPA. This difference is possibly due to data entry lag. According to BLM's Automated Fluid Mineral's Support System, 890 of these wells are federal wells. Using the COGCC well data, the completion dates for wells in the RPPA were determined and broken out by year in Table 2 (COGCC Library: Production and Prices).

Table 2. Wells spudded in the RPPA based on COGCC data.

Year	Wells Spudded above the Roan's Rim	Wells Spudded below the Roan's Rim	Total Wells Spudded in the RPPA
1960-1970	0	6	6
1970-1980	0	5	5
1980-1990	2	84	86
1990-2000	4	172	176
2000	0	39	39
2001	0	73	73
2002	0	106	106
2003	0	59	59
2004	0	182	182
2005	3	237	240
2006	3	337	340
2007	22	428	450
2008	29	369	398
2009	5	134	139
2010	9	154	163
2011	5	150	155
2012	0	44	44
Total:	**82**	**2579**	**2661**

Of the current wells, 47 of the wells are plugged and abandoned. The other wells are either producing gas wells or currently shut-in or temporarily abandoned. The wells in the RPPA are all classified as gas wells with some associated natural gas liquids (NGL). More than 2,600 RPPA wells are reported producing from the Mesaverde Formation. Approximately 90 wells are reported producing from the Wasatch Formation and 5 wells from the Mancos Formation (IHS Enerdeq). Current development is occurring below the plateau with some fee development above the rim using directional drilling.

Directional and New Technology Drilling Practices

Directional drilling in the RPPA and surrounding area occurs in the large majority of new wells, as it allows access to reservoirs from locations that are not directly over the reservoir, as well as the concentration of wells, facilities, roads, and associated surface disturbance in a single (and often smaller) area. Steep slopes or canyon (riparian) bottom areas may necessitate directional drilling to locate wells on mesa tops. Lease line locations and spacing may also force a directional drilling situation. Directional drilling is used extensively in the entire area. While new well pads are still being constructed, extensive use of directional drilling to multiple downhole locations from existing pads is also occurring. According to IHS Enerdeq (2013), 2,181 wells out of the 2,766 wells in the RPPA are s-curve directional wells and only 578 wells in the RPPA are vertical wells.

Operators in the CRVFO have directionally drilled as many as 52 wells from one pad (Webb). Many wells before the year 2000 were drilled vertically, but with the advent of more advanced completion techniques and with bottom hole densities at 10 acres for the Williams Fork Formation, the future will involve multi-well directional drilling from a single pad. Encana Oil & Gas (USA) Inc. proposed 60 wells on the WF H15 596 pad (DOI-BLM-CO-N040-2011-0110-EA). In the north Parachute field area, lateral reaches of the bottomhole location from the surface hole location are able to approach 4,877 feet (Webb). This kind of offset is dependent on the geology and reservoir characteristics, and most of the directional drilling within the CRVFO has a lateral reach around 2,500 feet. Economics is a major consideration—since directional drilling is generally more costly than drilling vertically, gas reserves need to be significant enough to recover costs in a reasonable amount of time and at a reasonable rate of return.

Slim-hole (diameter < 6”) drilling and completion, coiled tubing applications, high-energy gas fracturing, and new methods of well stimulation are currently being used within and around the RPPA and may play a part in an increased number of wells being drilled. These technologies make it more practical to explore in moderate- to high-risk wildcat areas. Slim holes cost less than large-diameter wells because the smaller rigs require less transportation and site preparation. In addition, the smaller wellbores record faster drilling times and have less expensive drilling tools, casing, and cement jobs.

Horizontal Drilling Practices

Currently horizontal drilling is still in the exploratory phase in the RPPA. Only seven (0.25%) of the wells in the RPPA are horizontal wells. According to IHS Enerdeq, six horizontal exploratory wells were drilled into the Mesaverde Formation group in the RPPA and one horizontal well was drilled into the Mancos Formation in the RPPA. Operators have since determined that horizontal drilling in the Mesaverde Formation group is not appropriate based on the Mesaverde geology. Refer to the Mesaverde geology description in the Description of Geology section for more information on the Mesaverde group.

To the west and south of the RPPA, operators have begun drilling horizontal wells into the Mancos formation. In general, the operators drill horizontal wells with one-mile horizontal legs that produce significant amounts of natural gas. The development is still exploratory and operators are attempting to determine the best drilling and completion practices for horizontal Mancos development.

Oil, Gas, and Water Production by Formation

Production within the RPPA is profiled by three producing gas horizons: the Mesaverde Formation, the Wasatch Formation, and the Mancos Formation. As of September 2013, the Mesaverde Formation was the most prolific with 1.74 TCF (96.7% of the total), while the Wasatch Formation totaled 56.17 BCF (3.1% of the total) and the Mancos Formation totaled 2.83 BCF (0.2% of the total). Rate verses time for the production of gas, oil, and water is illustrated for the Mesaverde Formation in Figure 2, Figure 3, and Figure 4. Figure 5, Figure 6, and Figure 7 illustrate the production history for the Wasatch Formation. Figure 8, Figure 9, and Figure 10 illustrate the production history for the Mancos Formation. The slight dip towards the end of each production curve reflects a partial year's production. The production data used to generate the production curves were retrieved from IHS Enerdeq Browser and created using PowerTools version 9.2 from IHS.

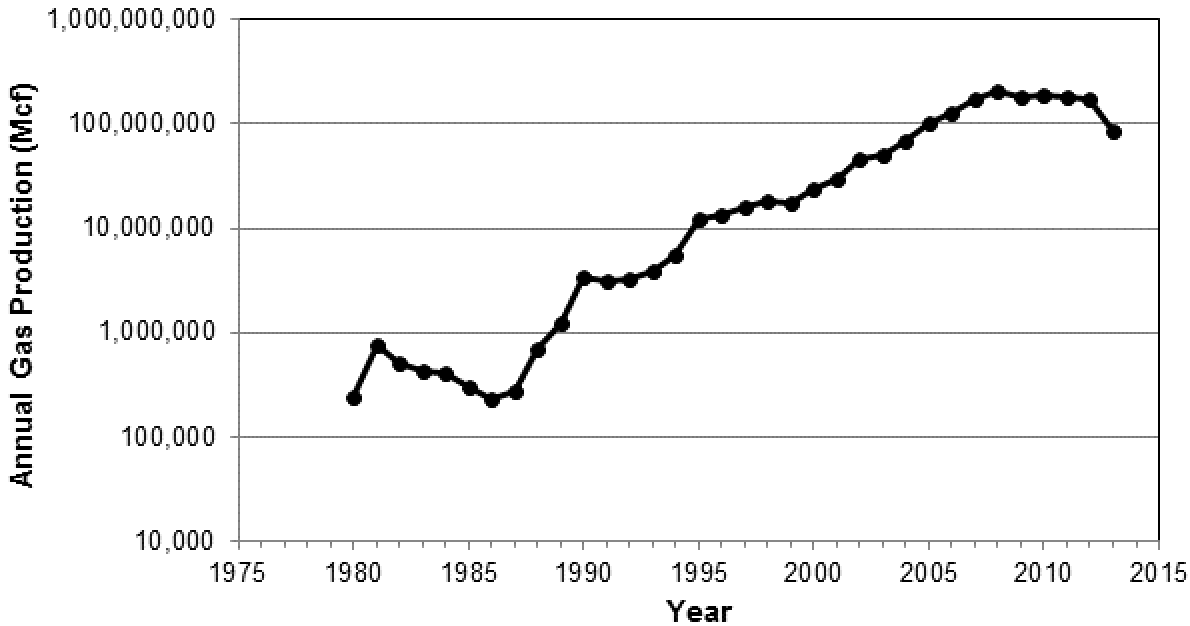

Figure 2. RPPA Mesaverde gas production history.

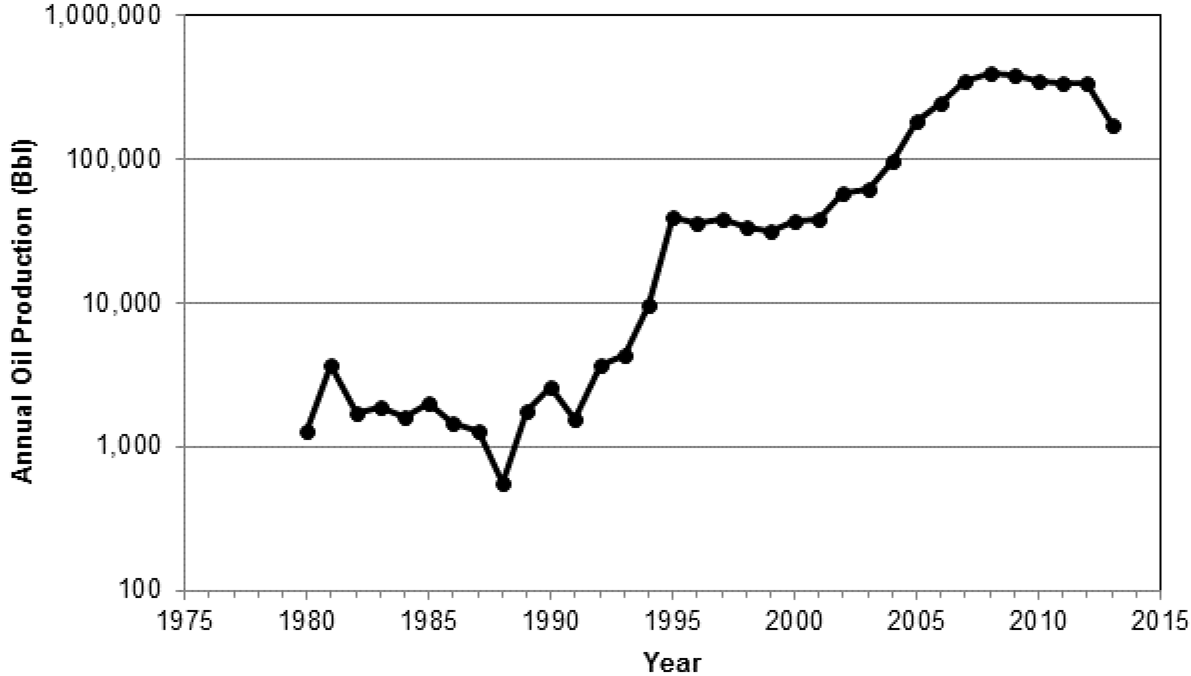

Figure 3. RPPA Mesaverde oil production history.

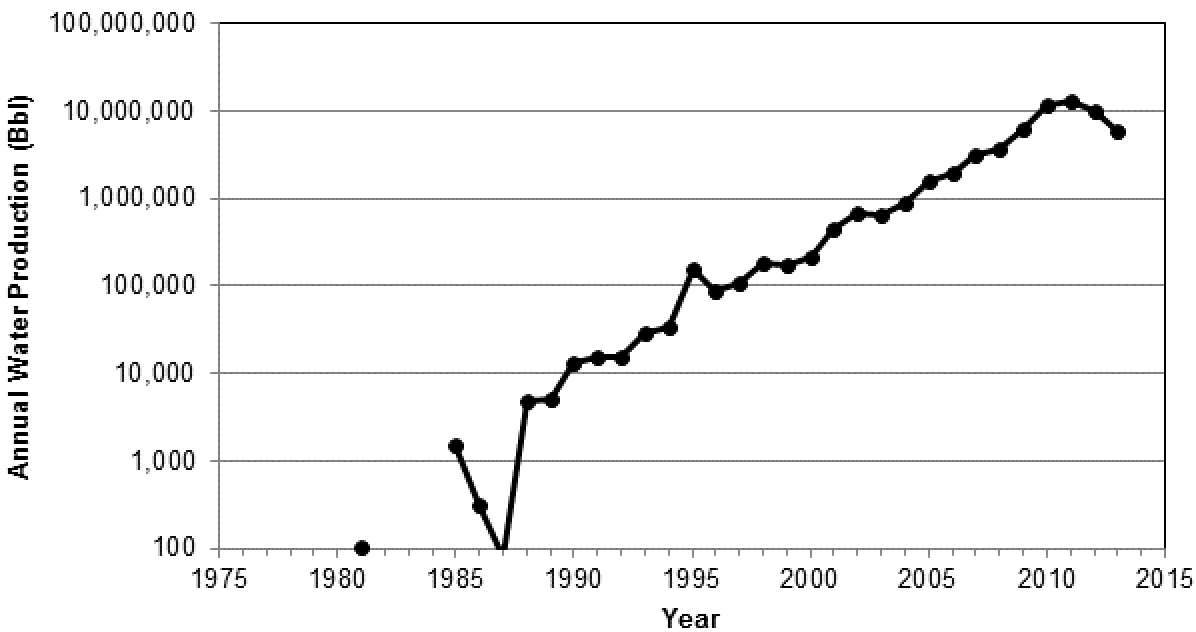

Figure 4. RPPA Mesaverde water production history.

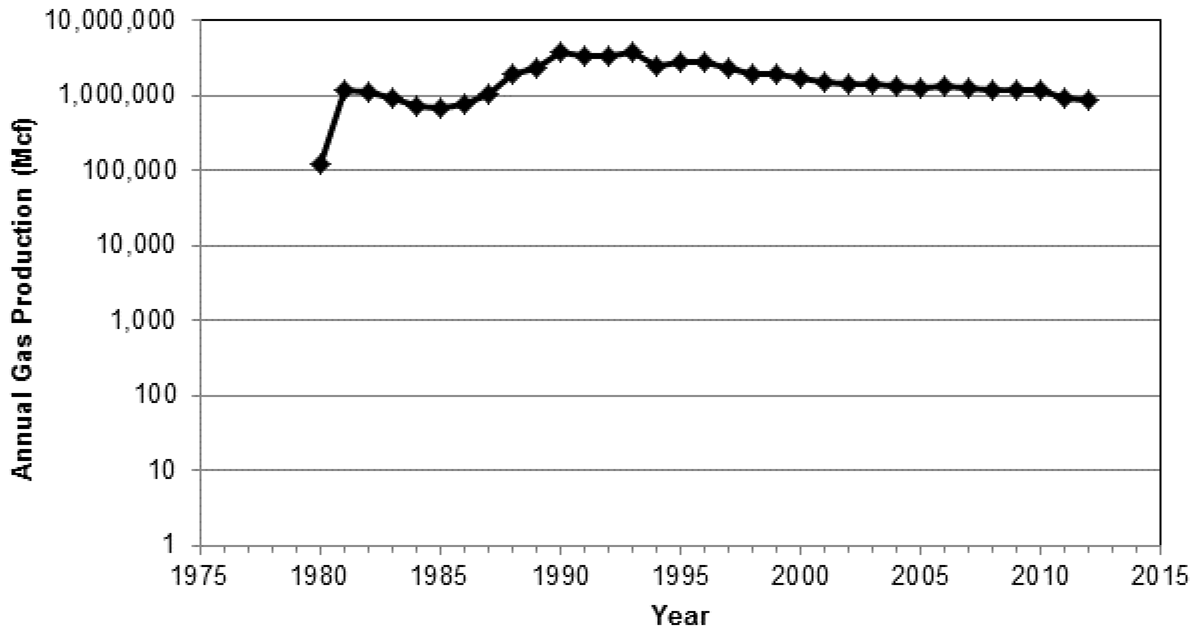

Figure 5. RPPA Wasatch gas production history.

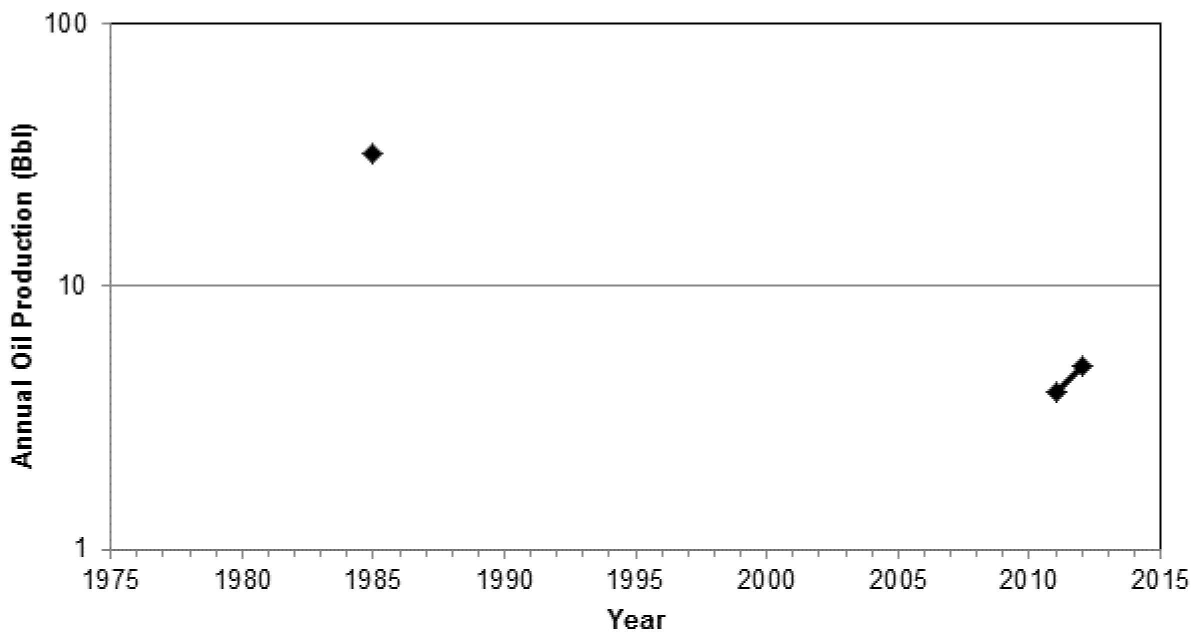

Figure 6. RPPA Wasatch oil production history.

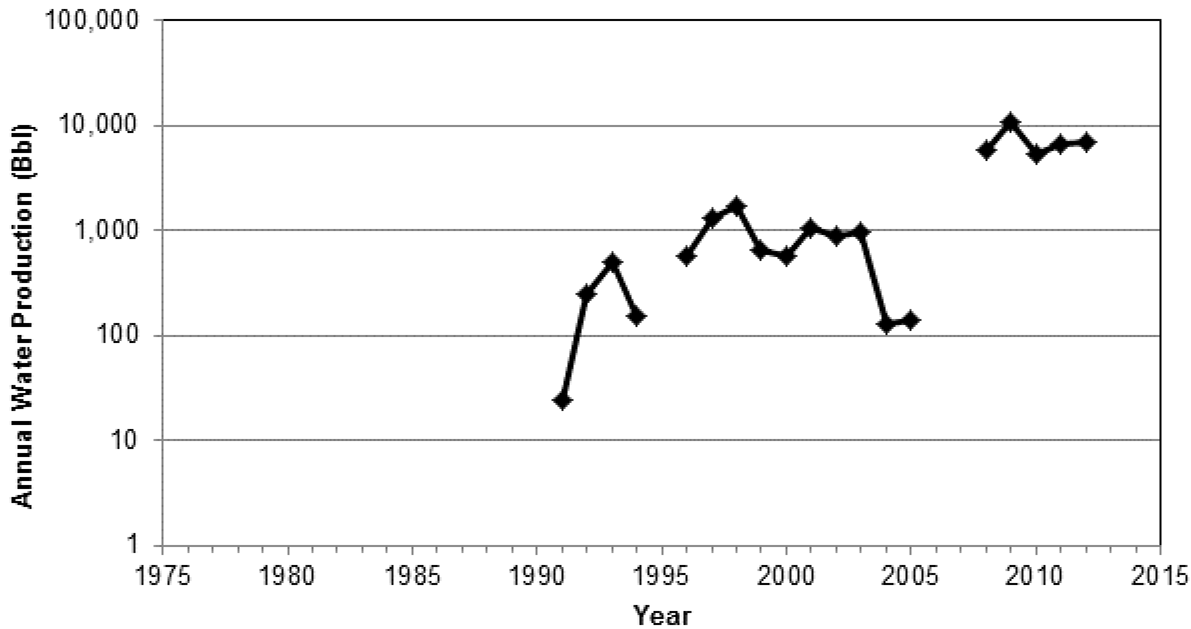

Figure 7. RPPA Wasatch water production history.

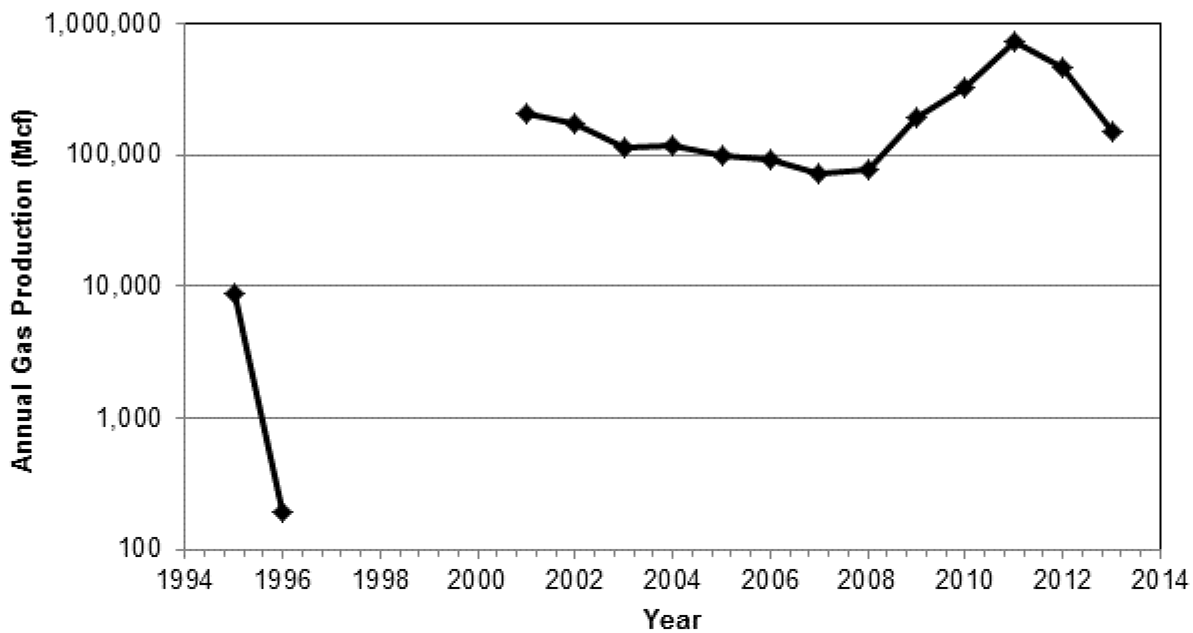

Figure 8. RPPA Mancos gas production history.

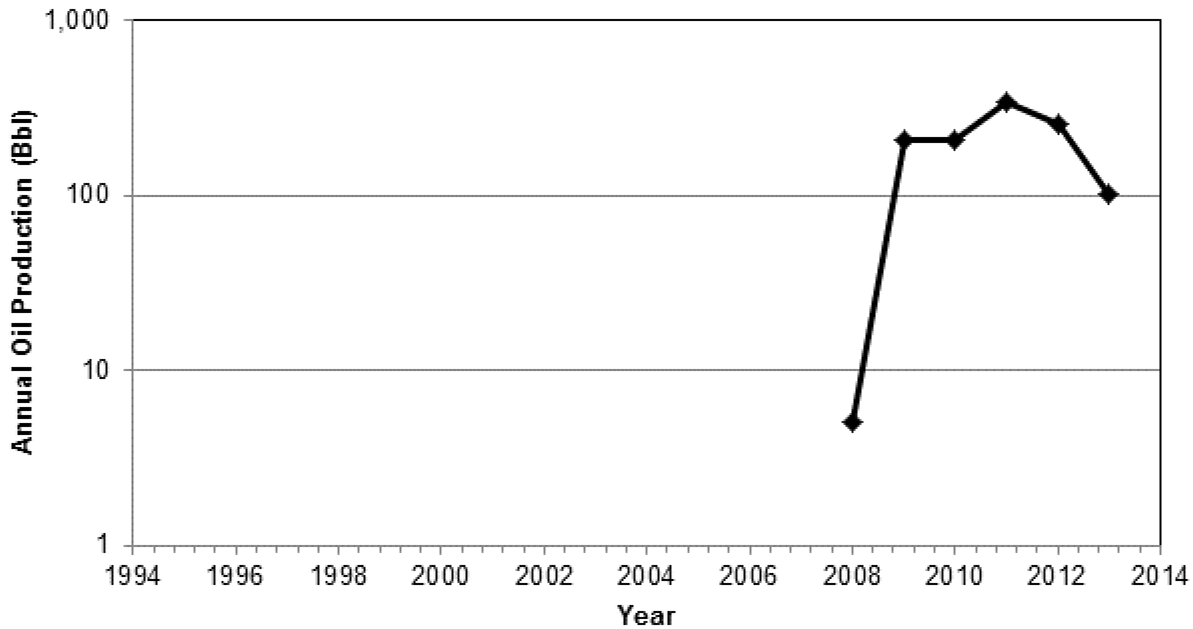

Figure 9. RPPA Mancos oil production history.

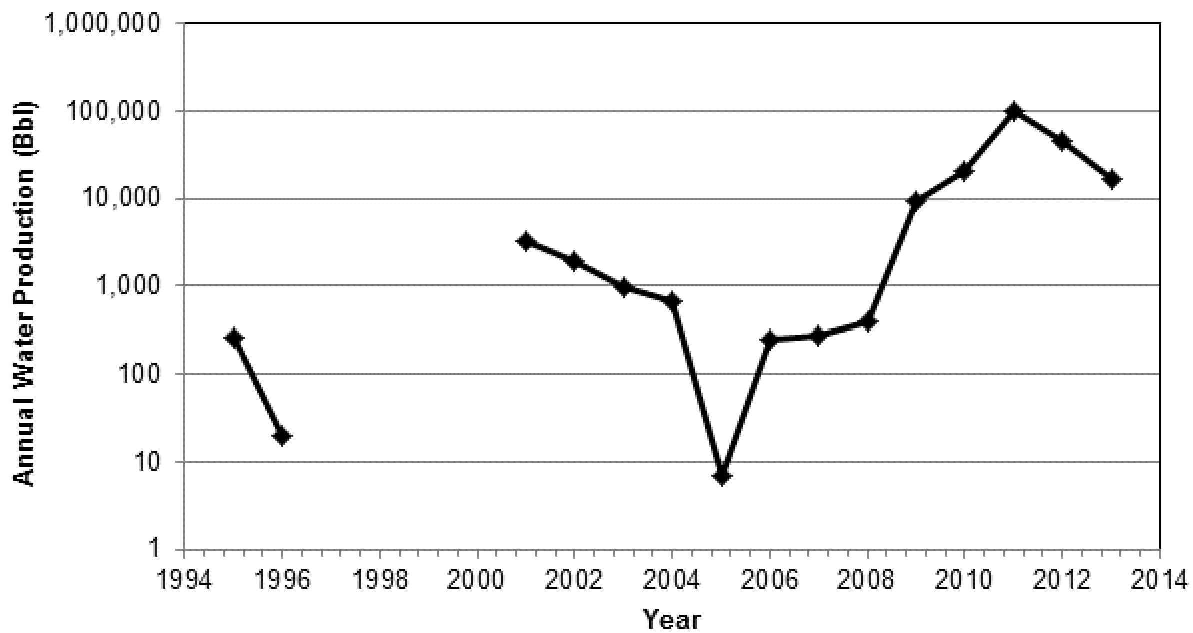

Figure 10. RPPA Mancos water production history.

Production Profiles

A normalized decline curve was generated using PowerTools analytical software to estimate the gas production rates for a typical well in the Mesaverde Formation within the RPPA. Gas production from approximately 2,670 Mesaverde wells was analyzed to generate a normalized production decline curve in Figure 11. The gas production rates were plotted versus time on a semi-logarithmic scale.

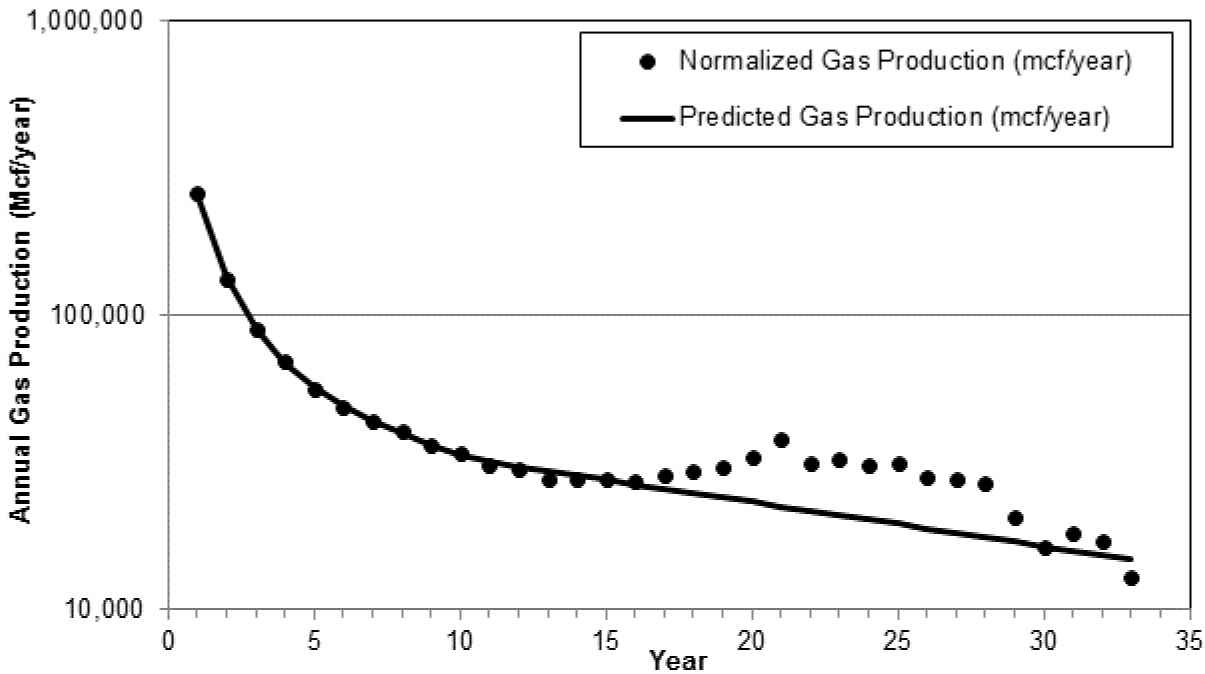

Figure 11. The normalized Mesaverde natural gas production decline curve.

It is believed the increase around year 16 in the normalized gas production is due to recompleting wells in additional productive zones in the Mesaverde Formation. Few of the Mesaverde wells in the RPPA are older than 15 years; therefore, the data past year 15 is generated by a smaller pool of wells and is less accurate. Year one used approximately 2,600 wells to determine the average production and year fifteen used an average of 106 wells. The gas production curve in Figure 11 approximates what a typical Mesaverde gas well might produce based on the expert and best fit method in PowerTools.

The decline curve shows a typical Mesaverde well has an initial natural gas production of approximately 260,000 MCF/year (712 MCF/day) and a final abandonment production of 16,500 MCF/year (45 MCF/day) in the thirty-third year. The gas production curve follows a hyperbolic decline for the first 9 years then an exponential decline for the rest of the well's life. PowerTools analysis shows an initial hyperbolic decline of 46.28%. After the ninth year, PowerTools estimates the production could decline at an exponential rate of 3.40%. The Reservoir Management Services and Gordon Engineering Inc. researched the low permeability wells in the Piceance Basin and determined that the Mesaverde well's production in the Piceance Basin is characterized by a sharp initial decline and then a slower exponential decline (Stright Jr. and Gordon). The decline curve generated in PowerTools matches the previous research.

Using these parameters, a typical Mesaverde well may ultimately recover approximately 1.35 BCF. Adjacent Reasonable Foreseeable Development Scenarios (RFD) have similar production values. The CRVFO office wide RFD estimated 1.15 BCF ultimate recovery and the Roan RFD from November 2005 estimated 1.17 BCF.

Similar to the natural gas production, the water and condensate production from the Mesaverde Formation were also analyzed in PowerTools. Both productions follow a similar decline path as the natural gas. Figure 12 displays the normalized Mesaverde water production and the best-fit decline curve from PowerTools. The water production rates were plotted versus time on a semi-logarithmic scale.

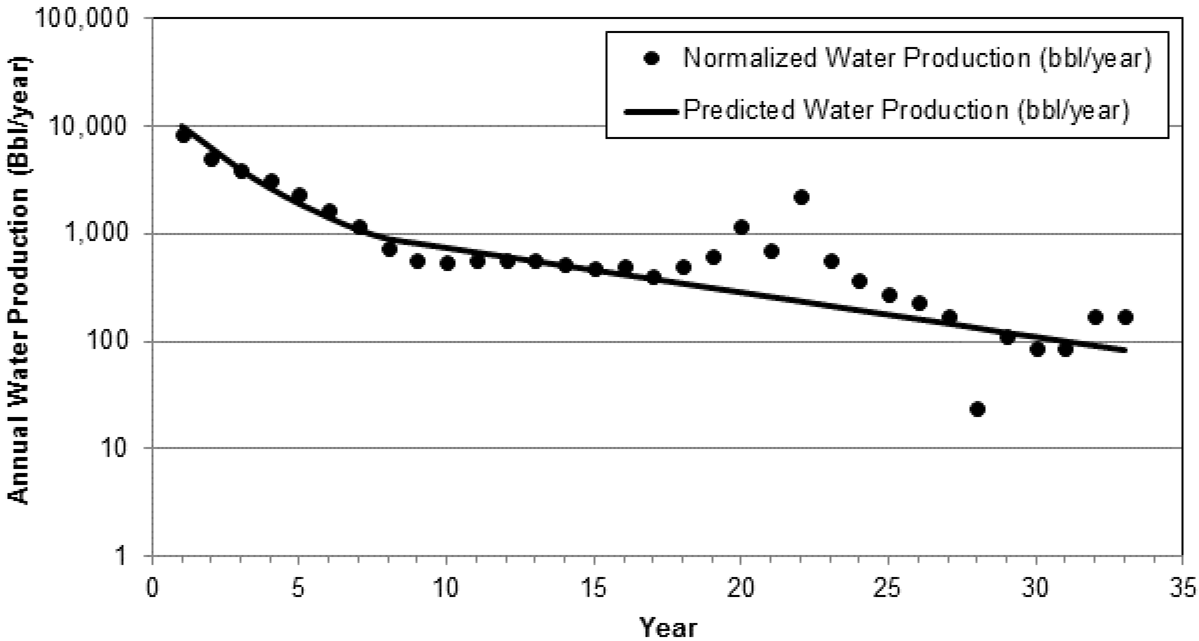

Figure 12. The normalized water production from the Mesaverde Formation.

The water production has an initial hyperbolic decline and an exponential decline after eight years. It is expected that a typical well producing from the Mesaverde Formation could produce approximately 38,000 barrels. The initial water production rates are projected to be an initial 8,500 barrels of water per year (bbl/year) that could fall off to around 100 bbl/year at the end of the well's life in year 33.

Although the Mesaverde Formation primarily produces natural gas, some condensate is also produced from the Mesaverde Formation in the RPPA. In the first year, a typical Mesaverde well could produce 550 barrels of condensate per year. By the end of the well's life, very little condensate production could remain. It is expected that a typical Mesaverde well could produce approximately 2,000 barrels of condensate by the end of the well's life. The oil and natural gas liquids produced from a typical well in the Mesaverde Formation is shown in Figure 13.

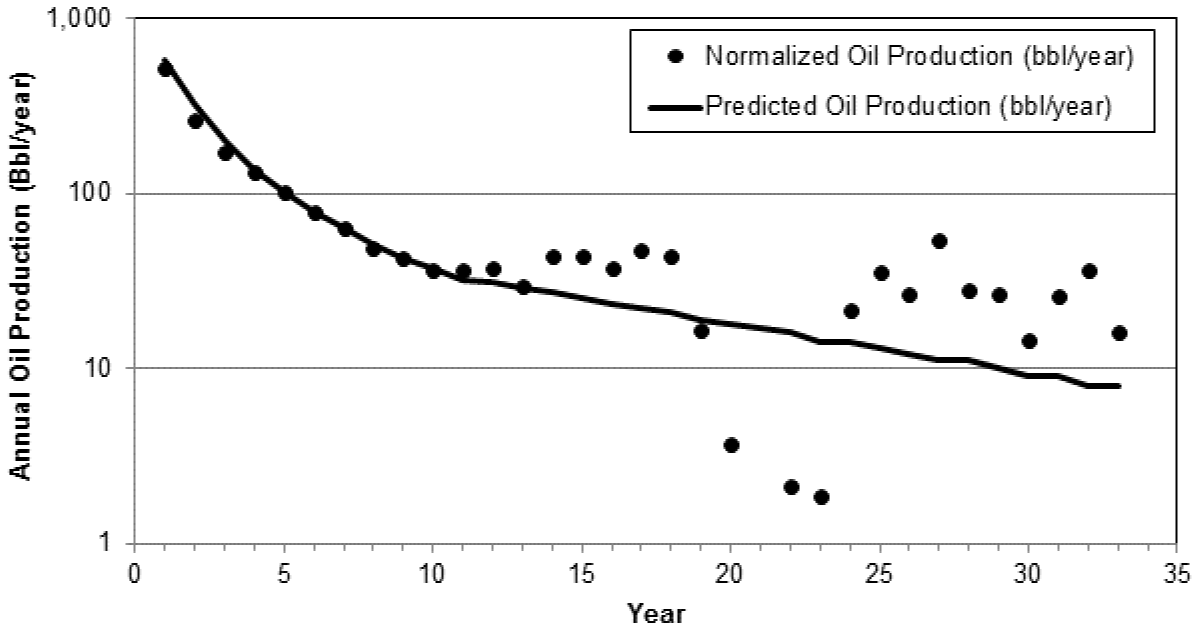

Figure 13. The normalized Mesaverde oil and NGL production decline curve.

Similar to the Mesaverde wells, the gas production from the 90 wells in the Wasatch Formation inside the RPPA was analyzed to generate a normalized production decline curve in Figure 14. The gas production rates were plotted versus time on a semi-logarithmic scale.

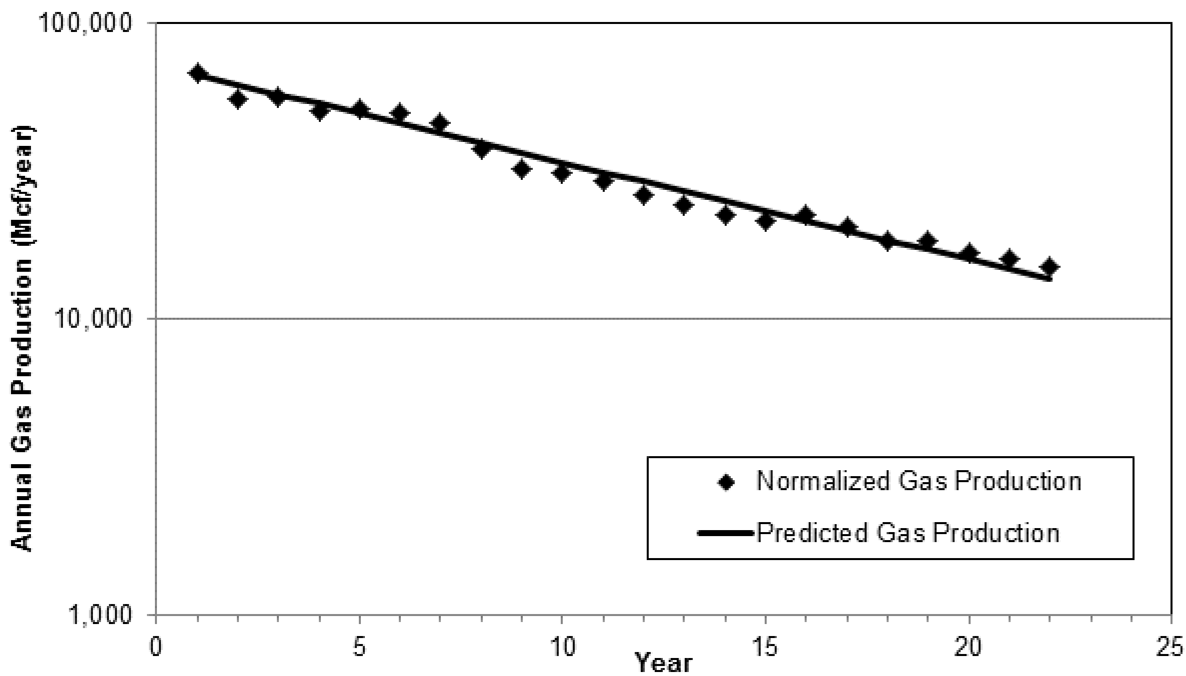

Figure 14. The normalized Wasatch production decline curve in the RPPA.

The decline curve shows a typical well in the Wasatch Formation has an initial production of approximately 67,000 MCF/year (183 MFC/day) and a final abandonment production of 15,000

MCF/year (41 MCF/day) in the twenty-second year. The gas production curve follows an exponential decline of 7.29%. Based on these parameters, a typical Wasatch well may ultimately recover approximately 0.74 BCF. The CRVFO office wide RFD had a similar estimate of 0.7 BCF.

The water production and condensate production were also reviewed in PowerTools. The Wasatch Formation produces a minimal amount of water. The normalized water production curve for the Wasatch Formation produces an average of 23 barrels of oil per year. The Wasatch Formation has little condensate production.

Not enough data was available to create a production profile for a typical well in the Mancos Formation. However, the surrounding fields suggest that decline curve for a well in the Mancos Formation could follow a similar decline path as the Mesaverde decline curve. Since the Mancos wells are usually horizontal wells, the Mancos wells produce more than the Mesaverde production but have a larger spacing requirement (Proctor).

Oil and Gas Prices, Finding and Development Costs

The price of oil and gas is dependent on the market. The industry standard is the New York Mercantile Exchange, Inc. (NYMEX), the world's largest physical commodity futures exchange and the preeminent trading forum for energy and precious metals. The NYMEX natural gas commodities contract is widely used as a national benchmark price. The price for natural gas is volatile and fluctuates with supply and demand and economic and political news. On September 24, 2013, posted prices ranged from \$3.49 to \$3.83 per million British thermal units (MMBTU) based on delivery at the Henry Hub in Louisiana. Based on data from the United States Energy Information Administration (EIA), Figure 15 shows the historical daily price trend from 2000 to 2013 and the future predicted prices (Annual Energy Outlook 2013).

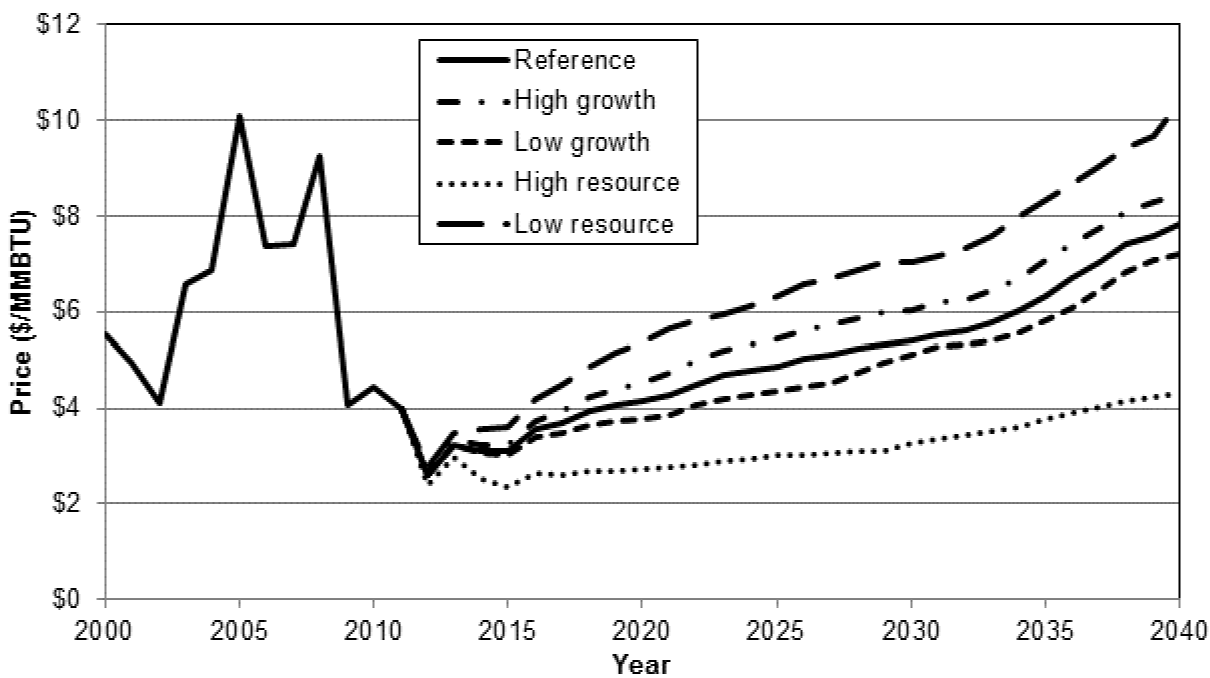

Figure 15. The natural gas spot and futures prices (NYMEX).

Based on the CRVFO field-wide RFD, the cost of finding and development natural gas and oil is about $125 per foot for drilling and $100 per foot for completion.

Two of the major cost items in the direct field operating cost are produced water disposal and gas processing. The estimated direct field operating cost in the RPPA would be similar to the CRVFO area and is estimated to be $0.33 per MCF (before taxes).

Gathering, Processing, Compression, and Transmission Costs

The RPPA has similar costs to the CRVFO field-wide RFD; therefore, these costs were pulled directly from CRVFO RFD. An average of $0.90 per MCF is typical based on in-field processing and compression. Upfront costs could increase on the plateau in the RPPA. The plateau‘s infrastructure is limited and has only supported hunters and range activities in the past. Pipelines exist on the western edge (fee surface) of the plateau, but the federal surface on the plateau would require pipelines for development to occur.

Field Production Equipment and Field Operation Practices

The field production equipment and operation practices are the same between the RPPA and the CRVFO field-wide RFD; therefore, the below discussion of practices were pulled directly from the CRVFO field-wide RFD.

For a multi-well pad, construction and reclamation costs are estimated at $100,000. The size and configuration of the well pad may cause this estimation to vary. The cost to equip a single well to produce to a sales line averages $70,000. This includes three-phase separation equipment (natural gas, condensate, and water), metering hookup, liquid storage tanks, and labor.

The natural gas from each well is individually measured after passing through the separation equipment on the well pad and then transported by pipeline to a processing plant. Associated condensate is collected and gauged in storage tanks, then trucked to an offsite sales collection facility. A portion of the gas is used at the facility to operate fired vessels, control systems, pumps, compressors, gas-lift systems, etc. Sometimes, the gas may be flared or vented.

Gas Transportation Pipelines

After gas is individually treated, separated and measured, it travels through a 4-inch to 8-inch diameter steel line (line pressures range: 100 psi to 1,000 psi) from the well pad to field compression facilities and then to a buried cross-country trunk pipeline. Trunk pipelines in the area have diameters between 12 and 36 inches and can cost as much as $2,000,000 per mile for a 36-inch line. The trunk pipelines carry wet, unprocessed gas-to-gas treatment facilities. After processing, the dry gas is transported to local markets or out of the Piceance Basin in one of several 24-inch lines

Gas Compression Facilities

Typically, two types of gas compression facilities are used in the area. Gas-driven compression can either be a permanent or temporary installation, whereas electric-driven compression is normally a permanent installation. A major variance is the lack of emissions with the electric driven compressors. The limitations of electric-driven compressors are power supply requirements and installation costs. These costs are typically 30% higher than gas-driven compressors.

Electrical Power Lines, Generators, and Roads

The need for electrical power on a well pad is minimal in the area, as power is typically supplied by natural gas generators. The majority of the field compressors are natural gas driven; however; as stated above, electric-driven compressors have recently been introduced.

Roads used for oil and gas operations require an average 35-foot-wide right-of-way. Below the rim, the RPPA has extensive oil and gas roads and infrastructure in place; however, above the rim, there is only a small amount of oil and gas development on the fee surface of the RPPA. The federal surface on the plateau in the RPPA has roads used for grazing and hunting. The average road width is around 15-feet. The road on the federal surface above the rim would require upgrades before drilling can occur. The amount of roads needed would depend on the well spacing, the amount of use of multi-well pads, terrain, environmental constraints, land ownership patterns, and existing road infrastructure. The topography of the area has an impact on the length of road needed and the cost. Hilly terrain would need a road to fit the terrain and cut-and fill construction to meet slope requirements.

The CRVFO requires that oil and gas operators use existing roads and two-tracks where possible to minimize surface disturbance. Flat blading is allowed and crowned, and ditched roads are not always required for wildcat wells (except on National Forest lands) to encourage minimal disturbance to the surface estate. The reasoning is that if the well is a dry hole, reclamation is more efficient and cost effective. If a wildcat well proves to be productive, the road must be upgraded to an all-weather road and meet more stringent construction standards.

Conflicts with Other Mineral Development

Saleable minerals such as sand and gravel are plentiful in northwest Colorado and are widely scattered throughout the CRVFO. These small mining operations can easily be avoided by oil and gas operators and, as a result, conflicts do not exist. Conflicts between oil and gas and coal typically do not occur but, if they were to occur, they would be governed by a No Surface Occupancy (NSO) stipulation (Stip. Code: CO-01) listed in the Record of Decision (1991) for the Oil and Gas Development and Leasing EIS.

Future conflicts between oil shale development and gas development on the Roan Plateau could arise. The existing leases on the plateau in the RPPA, which are currently under suspension, contain stipulations that limit drilling opportunities. According to these stipulations, only 1% of the top of the plateau can be in a disturbed condition due to un-reclaimed oil and gas activities. Therefore, current restrictions will not allow for both the extraction of natural gas and oil shale from the surface. However, if new technologies allow oil shale to be economically developed using underground mining or in-situ techniques versus extraction from the surface, this may allow oil shale extraction to be performed in conjunction with gas development.

Oil and Gas Occurrence Potential

Review of RFD Prepared for Areas Adjacent to the Study Area

Management plans and/or RFDs for BLM's White River Field Office, Grand Junction Field Office, and the Colorado River Valley Field Office were reviewed. This review provided information helpful in looking at adjacent oil and gas exploration and development that may affect the RPPA RFD. In addition, basin-wide studies performed by the National Petroleum Council and the USGS, and the Energy Policy and Conservation Act (EPCA) study were reviewed to enhance the quality of the RPPA RFD. CRVFO staff members also review RMPs from surrounding field offices and look for consistencies, inconsistencies, and new approaches or ideas to mitigate impacts from oil and gas exploration and development activities. This should facilitate consistency by BLM in managing oil and gas resources across field office boundaries.

Resources, Plays, and Oil and Gas Assessments

The DOE prepared two reports that discussed reserves, development potential and geology for the Naval Oil Shale Reserves (NOSR) 1 and 3. The first is entitled, "Naval Oil Shale Reserves 1 and 3 Oil and Gas Reserves Evaluation" and the second is entitled, "Naval Oil Shale Reserve No. 3 Commercial Development Study". Both were prepared in July 1998. Geologic studies were also conducted in 1988 and 1990as part of the Department of Energy's Multi Well Experiment (MWX), which characterized the Mesaverde low permeability reservoirs and developed technology for their production. In addition, Ron Gunnufson, BLM Colorado State Office Geologist, prepared a report on the geologic potential of the area on October 14, 1999 and Brian Macke (Director of the Colorado Oil and Gas Conservation Commission) prepared a related report on August 26, 2005. The USGS prepared an oil and gas assessment report in 2003 for the Piceance Basin. The following discussion incorporates information from those reports, except where otherwise noted. For greater discussion on AUs, see the Description of Geology section.

Williams Fork Formation

The principal drilling objective in the RPPA is the gas-bearing fluvial sand section present in the Williams Fork Formation of the Mesaverde Group. This includes the Cameo Member found directly above the prominent Rollins Sandstone at the base of the Williams Fork. The Williams Fork is approximately 3,600 feet thick (Rulison Field), of which the lower 2,400 feet is gas saturated in the Rulison Field, and lower 1,500 feet in the Grand Valley Field. In the lower plateau, depth to the base of the Williams Fork (Rollins Sandstone) is about 7,000-8,000 feet. On the upper plateau, depths are about 3,000 feet greater.

The fluvial section in the Williams Fork Formation consists almost totally of lenticular channel sandstones and fine-grained flood plain deposits, which were deposited on a coastal plain behind the retreating Late Cretaceous coastline. (Lorenz) best described this section as consisting of meander belt river-channel sandstones inter-bedded with muddy flood plain, levee and swamp deposits. Lorenz stated that the average meander-belt width for the fluvial section of the Williams Fork Formation is 1,500 feet but within that meander-belt width are numerous point bar deposits, with each sandstone body generally not exceeding 700-800 feet in width. The point bar sand bodies are stacked vertically throughout the thickness of the formation. Studies show that the point-bar reservoirs are layered, do not communicate vertically, are naturally isolated from each other, have an asymmetric drainage pattern based on natural fracture distribution, and that drainage from a well is limited to the aerial extent of the point bar sand bodies. This explains why wells that penetrate the fluvial section encounter 10 to 25 + different, individual sandstone reservoirs that are tight and lenticular with very limited extent. These discontinuous and compartmentalized sand bodies have a very limited aerial extent, which requires that wells be drilled closer together in order to adequately recover the gas and associated hydrocarbons and prevent resource waste.

The lenticular nature of the fluvial sandstone reservoirs forms the major trapping mechanism at Rulison, Parachute and Grand Valley Fields with regional extension fractures enhancing this production. The source rocks for the fluvial section are the Cameo Coals and associated carbonaceous shales.

Production rates from the sands are highly variable and are a function of depth, porosity and permeability, continuity of individual sands, degree of natural fracturing, number of sands penetrated and other geologic factors, which vary from well to well. The Williams Fork gas wells produce some associated condensate but little water. Initial well production for Williams Fork wells averages 1,360 MCF/day. During an April 2001, spacing hearing before the Colorado Oil and Gas Conservation Commission, Williams estimated Mesaverde reserves to be 1.25 -1.86 BCF/Well.

Geologically, there is little risk in extending the existing Grand Valley, Parachute and Rulison Fields into NOSR-1. It is expected that the Williams Fork gas saturated zone will probably underlie most of the plateau. Very few dry holes have been drilled in the Grand Valley, Parachute and Rulison Fields due to the nature of the play. Risks are minimized because the wells are drilled into a pre-dominantly gas saturated section encompassing an enormous area. Gas sand reservoirs may lack continuity and may not be correlative between closely spaced wells, but each well will penetrate numerous productive reservoirs, unique to that well. There are smaller risks related to the geologic and engineering heterogeneities (such as permeability, porosity, faults, fracture systems, structural irregularities, etc.) that are unique to each well, which is evidenced by the large range in production rates.

Wasatch Formation

The DOE report considered the Wasatch reserves as second only to Mesaverde potential. The Wasatch Formation is Eocene to Paleocene in age and consists of multiple, lenticular sandstone lenses interbedded with bentonitic varicolored shales and siltstones. The sands of the Wasatch were deposited as channels cut into the shales and siltstones. The sands that usually contain high clay content are considered "tight" with low permeability.

It is expected that most of the Wasatch production in the RPPA to originate from the G Sand of the Molina Member. Production has been established in the G Sand in the Rulison, Parachute and Grand Valley Fields. Due to the heterogeneous make-up of this formation, trapping mechanisms are normally stratigraphic in nature. Economic gas production rates and recoveries are highly dependent on natural and induced fracture systems within the reservoirs. Below the rim, the Wasatch Formation is found from the surface down to a depth of about 3500 feet. Most production from this formation has been derived from depths between 2,000-3,000 feet. Wasatch reserves are estimated to be about 0.7 BCF/Well and initial well production averages 270 MCF/day.

One factor affecting potential Wasatch development could be the relatively deep drilling depths required to reach the "G Sand" and the other reservoirs of the Wasatch on top of the plateau since the top is about 3,000 feet higher than the majority of the producing wells situated to the south. In December of 1990, Barrett Resources Corporation completed a Wasatch G Sand well only 1179 feet from the southern boundary of NOSR-1. The Allen Point #1-8-95 was completed between the depths of 5887-5933 feet and had an initial well production of 230 MCF/day with no oil and no water. The ground surface elevation of this well was 8,516 feet. If the Wasatch G Sand approaches a depth of nearly 6,000 feet near the southern boundary of NOSR-1 (and structurally the regional dip underlying much of this area is to the northeast) then depths to the G Sand could be in excess of 7,000 feet. Traditionally, in many areas of northwestern Colorado, the Wasatch has been developed at depths between 2,000-3,000 feet with typical initial well productions of 200-300 MCF/day.

Coalbed Natural Gas

The Cameo Coal Zone is the basal member of the Williams Fork Formation, and the coalbeds represent a potential reservoir component within the Mesaverde Group. This section reflects a paludal (swamp) depositional environment landward of the prograding Rollins paleoshoreline. In the Grand Valley Field, the Cameo coal zone is about 470 feet thick and contains 50 to 70 feet of net coal with the thicker coals occurring near the base of the zone. The zone thickens regionally from the Grand Valley Field to the Parachute Field.

While CBNG exists in the Cameo coals, they lack the well-developed natural fracture permeability associated with prolific water and gas flows exhibited in some areas of the northern San Juan Basin and on the Divide Creek anticline in the eastern Piceance Basin. Well test data from the Parachute Field indicate that in situ coal permeability ranges from 0.02 to 0.2 mD. In the Grand Valley Field, the absence of well-developed cleat systems and the lack of abundant open fractures are probably related to the depth of rock overlying the coals and to the lack of faulting in the area. With the exception of any structurally impacted areas on top of the plateau, coalbeds could be subjected to even less fracturing, with greater thicknesses of overburden, resulting in less developed cleat and fracture systems, which would equate to less gas production.

The CBNG potential was also evaluated in several studies that concluded that permeability in coals is significantly reduced with depth. At a depth around 7,000, the permeability would be so low that coalbed methane could not flow in economic quantities. The USGS geologic assessment of oil and gas (2003) delineated a coalbed natural gas area in the Grand Valley and Parachute fields to a depth of 7,000 based on Barrett Resources completing 51 wells in the coalbeds to near that depth between 1989 and 1992. However, USGS noted that most of the wells were dual coalbed and sandstone completions, and that the coalbeds were contributing only small amounts of gas to the overall production. The DOE's Coalbed Methane Primer (2004) noted that due to the depth of Piceance Basin coals, permeability is reduced, thereby hindering extraction.

It should be noted that the Cameo coals in the White River Dome area in the northeastern part of the Piceance Basin are productive at deeper depths. CBNG production has occurred down to a depth of 8,140' (Olson). The coals have low permeability, but higher than the sandstones. Coal permeability is derived from the cleats and natural fractures. Although there are current problems associated with commercial development of CBNG within the RPPA, the actual potential is unknown.

Iles Formation

The Iles Formation underlies the Williams Fork Formation and comprises the lowest part of the Mesaverde Group. The Rollins, Cozzette, and Corcoran Sandstone Members reflect distributary channel, and beach (shoreline and offshore bar sands) depositional environments. Significant gas production from the Cozzette and Corcoran Sandstones occurs in other fields to the south and west, but is minimal within the RPPA. Therefore, the actual potential of this resource is unknown.

Mancos Shale, Dakota Sandstone

The DOE report states that hydrocarbons could exist in the Upper Cretaceous Mancos Shale in fractured reservoirs, in the Lower Cretaceous Dakota Sandstone and Cedar Mountain-Burro Canyon Formations, Jurassic Morrison Formation and in Paleozoic strata. With the possible exception of the Mancos Shale, all of the above formations would probably occur at depths in excess of 15,000 feet, which significantly reduces their importance as viable objectives in this area. In addition the Cedar Mountain-Burro Canyon Formations are actually stratigraphic lateral equivalents, and the Cedar Mountain component present in portions of northwestern Colorado may actually be absent in the NOSR-1 area.

Rationale for selecting values of occurrence potential and certainty

The rationale for selecting values of occurrence potential and certainty is discussed below. The classification was modified from the BLM Handbook H-1624-1, dated May 7, 1990, and derived from a variety of sources; such as the EPCA inventory resource density polygons, reserve estimates from PI Dwight's Digital Well Data and Production Data, USGS TPS and AU maps, and USGS geologic maps.

- High – Demonstrate existence of source rock, thermal maturation, reservoir strata possessing suitable permeability and porosity, and traps. Demonstrated existence is defined by physical evidence or documentation in the literature. The high potential occurs in areas inside total petroleum systems and geologic basins with extensive Cretaceous and Tertiary sediments such as the Piceance Basin within the CRVFO boundary.

- Medium – Geophysical or geological indications that the following may be present: source rock, thermal maturation, reservoir strata possessing suitable permeability and porosity, and traps. Geologic indication is defined by geological inference based on direct and/or indirect evidence. Occurs in the Eagle Basin, which is known to be marginal for the economic occurrence for oil and gas, areas of thick sediment that contain some lower Mesozoic sediments along with Paleozoic sediments, and areas where existing well data show some evidence of hydrocarbons.

- Low – Specific indications that one or more of the following may not be present: source rock, thermal maturation, or reservoir strata possessing permeability and porosity, and traps. Occurs in areas outside USGS petroleum system and productive basin margins, where little or no hydrocarbon resources are indicated by existing well data. Also in areas where the basin sediments are less than 5,000 feet thick and consist mostly of Jurassic and older rocks as evidenced by existing well data.

- No Known Potential – Demonstrate absence of source rock, thermal maturation, reservoir rock, and traps. Demonstrated absence is defined by physical evidence or documentation in the literature. Occurs in areas outside the EPCA resource boundaries and USGS TPS and productive basin margins. Also in areas of Cambrian and Precambrian igneous and metamorphic rocks, not overlying favorable sedimentary environments. These areas may be unconformably overlain by thin younger sediments.

Note: Inclusion of an area in a USGS oil and gas play defined in the 2002 national assessment should be considered in determining potential for oil and gas occurrence. However, because the USGS assesses speculative plays, play definition alone should not be the only criterion for determining occurrence potential.

Oil and Gas Development Potential

The high potential area for natural gas includes all acres in the RPPA. Operators expressed a high degree of interest in the federal minerals in 2007 and 2008. At today's natural gas prices, interest has waned; however, natural gas prices will likely return to a higher rate in the future, which would increase the pace of development in the area.

RFD Scenarios for Plan Revisions

Three BLM field offices and one national forest share similar geology and oil and gas potential with the RPPA, since all four are located within the southern Piceance Basin. The White River Field Office (WRFO) manages the federal minerals north of the RPPA and finalized an RFD in 2007. The WRFO RFD estimates 17,800 wells to be drilled in the next 20 years. The Grand Junction Field Office (GJFO) finalized a RFD in June 2012. The GJFO estimates 8,403 wells to be drilled in the next 20 years. The CRVFO office wide RFD estimates 14,792 wells to be drilled in the next 20 years. These numbers include both fee and federal wells. The White River National Forest, which is a large part of the surface area within the CRVFO, the GJFO, and the WRFO, is working closely with both the CRVFO and the

GJFO to revise their estimated oil and gas activity. There should be no conflict of estimates for future development potential between the BLM and USFS offices.

Values of Development Potential

The future development for the RPPA is based on past development seen in the RPPA and surrounding areas. The main criteria for future development are the area's geology, current technology, and estimated future natural gas prices. The area's geology has already been established as high potential throughout the RPPA and the current technology was discussed previously in the section on Past and Present Oil and Gas Development Activity. The critical aspect for operator's to drill a well is therefore the natural gas prices. Combining Table 2 and Figure 15, the price of natural gas and the number of wells spud is graphed per year in Figure 16.

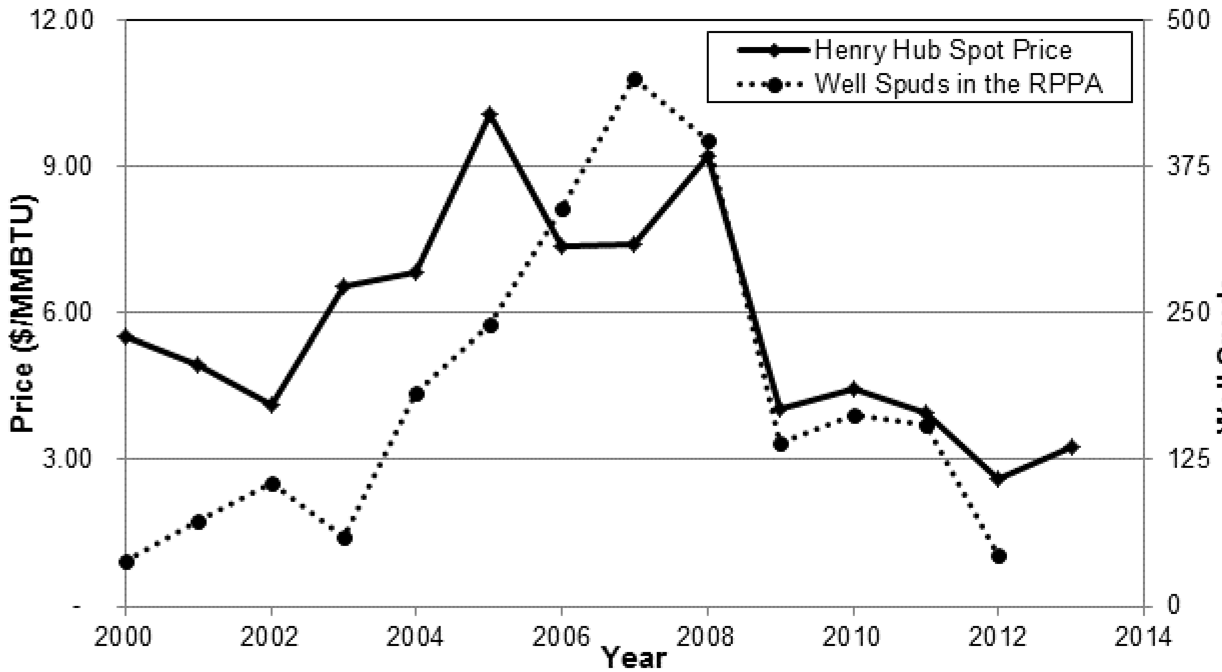

Figure 16. A comparison of the number of RPPA well spuds and the price of natural gas.

The number of spudded wells per year trends with the price of natural gas. Initially the wells lag behind the change in price, which might be due to the lack of infrastructure needed to produce all the wells. Based on this relationship, a trend line can be created to model future development based on the predicted price of natural gas. Since the cost to drill a well is higher when above the rim, the price of natural gas and the number of wells spud were modelled for two geographic areas: below the rim in the RPPA and above 8,000' in and around the RPPA. A scatter plot of the price versus the wells spud below the rim in the RPPA is created between 2006 and 2012 in Figure 17 with a trend line.

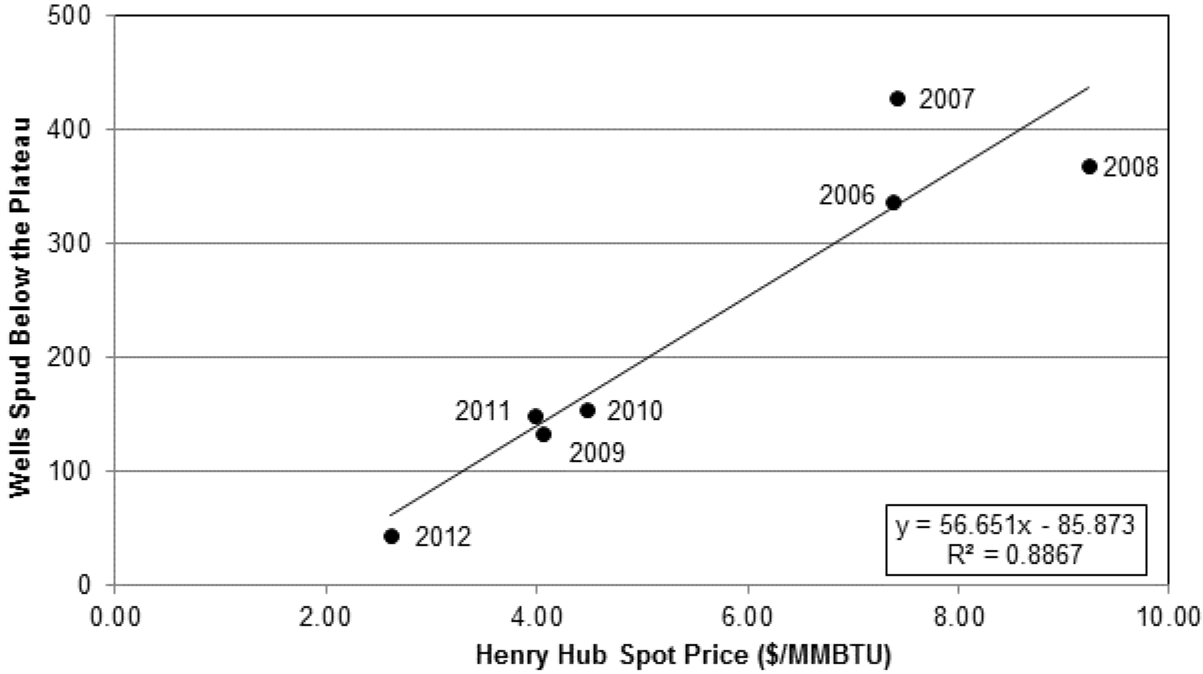

Figure 17. Number of well spuds below the plateau versus the price of natural gas.

The trend line in Figure 17 represents a historical relationship between the price of natural gas and the number of wells spud in the RPPA and below the rim each year. Using the trend line and the predicted natural gas prices in Figure 15 from NYMEX, the potential number of wells to be drilled below the plateau in the RPPA is determined. The average reference price between 2016 and 2035 is $4.89/MMBTU which is approximately 190 wells/year based on the trend line from Figure 17.

Little past development has occurred atop the plateau in the RPPA. Only 82 wells have been spud on top of the plateau, which is an insufficient data set to determine an accurate relationship between past and future development. Wells drilled into adjacent lands with similar elevation, topography, and geology were included to analyze the future potential development atop the plateau in the RPPA. The top of the plateau, which is between 7,500 and 9,300 feet above sea level, has greater drilling depths then below the rim, considering the lowest point in the RPPA below the rim is 5,100 feet above sea level at the confluence of Parachute Creek with the Colorado River. Refer to Figure 21 on page 42 for the topography in the RPPA. For this reason, the criteria used to pull the well data included: wells above 8,000’ in elevation and wells east of Township 5 South Range 98 West and Township 5 South Range 97 West. West of the barrier, the geology begins differing from the RPPA. The area described above is shown in Figure 26 on page 47.

Using ArcMap and COGCC well data, 1,189 wells were determined to have similar characteristics as future wells atop the plateau in the RPPA. The majority of the wells were located in the Book Cliffs area between Debeque and Parachute. A graph was then generated to determine the relationship for wells drilled in areas similar to the plateau in the RPPA as seen in Figure 18. Years before 2008 were not modelled since there was significant lag between a change in price and development until 2008.

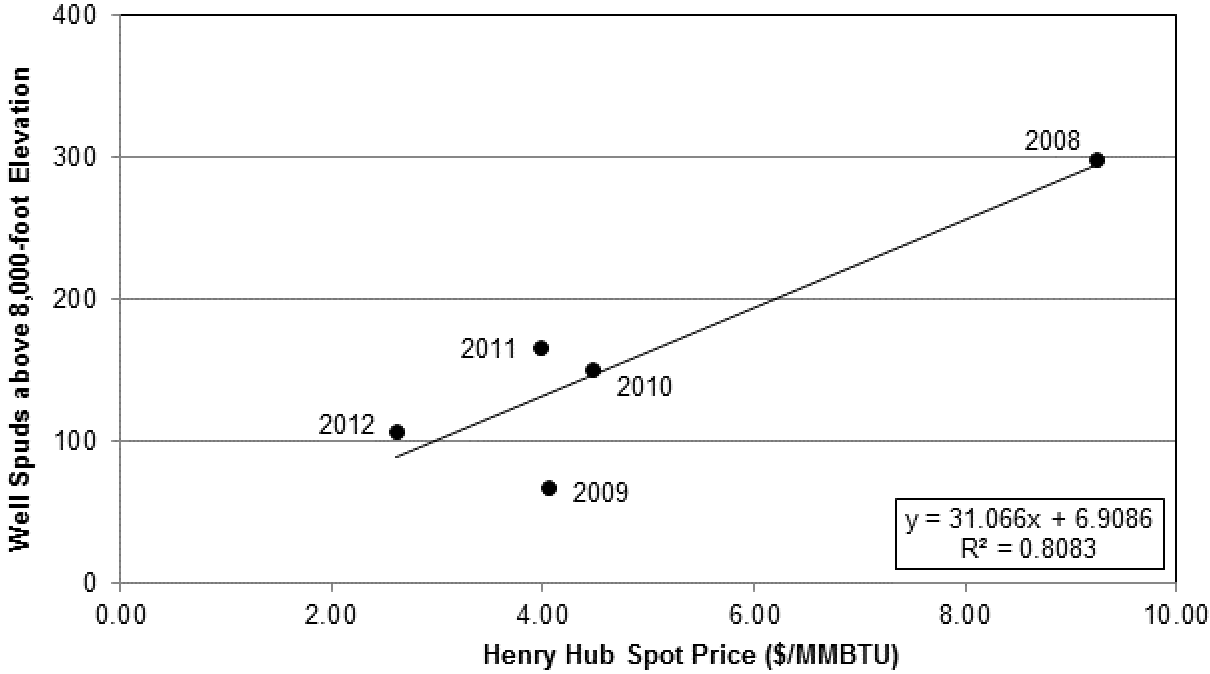

Figure 18. Number of well spuds above the 8,000-foot elevation versus the price of natural gas.

Since the 8,000-foot elevation area includes lands outside the RPPA, a ratio was used to determine the potential development on the plateau. The 8,000-foot area includes 135,327 acres; however, 33,000 of the acres are leased but under suspension and no development could occur. The plateau in the RPPA has 54,525 acres. Therefore, the equation based on the trend line was divided by 102,327 acres and then multiplied by 54,525 acres to create an equation able to approximate future development on the plateau in the RPPA. The new equation is $y = 16.55x+3.68$ where y equals the potential wells to be drilled atop the plateau in the RPPA and x equals the Henry Hub Spot Price. The average reference price between 2016 and 2035 is $4.89/MMBTU which is approximately 85 wells/year based on the new equation.

Using the two relationships, the potential number of well spuds is determined for the RPPA based on the price of natural gas. Figure 19 was created to show the different development possibilities in the RPPA based on the price of natural gas predicted in Figure 15. Years 2014 through 2016 estimate a lower number of wells on the plateau in the RPPA. Since the federal leases are still under suspension, development would only occur on the fee estate and federal minerals leased prior to 2008. This is approximately 72,260 acres.

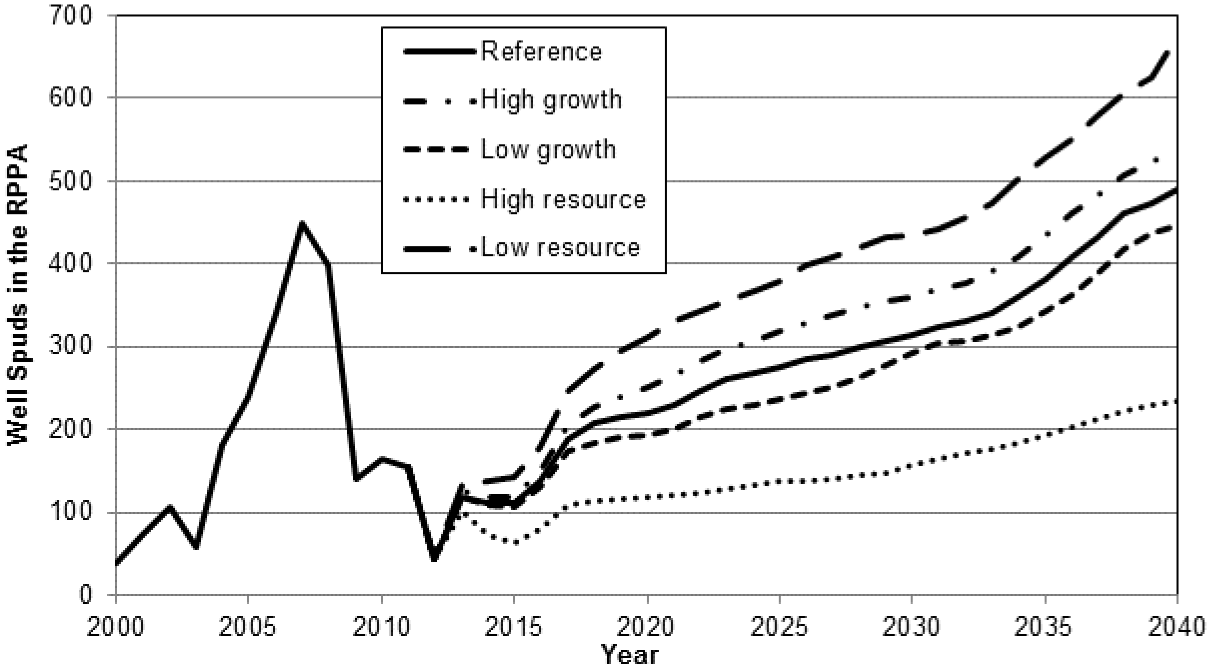

Figure 19. Potential future wells based on the NYMEX price of natural gas.

The reference natural gas price predictions were used to determine future development in the RPPA. Between 2016 and 2035, the equations estimated 3,820 wells below the plateau and 1,650 wells on the plateau in the RPPA. Based on the existing mineral acreage and existing wells, the potential wells were split between the federal and fee minerals in the RPPA. Table 3 breaks down the well numbers over the next 20 years for the RPPA.

Table 3. Well spuds potential within the RPPA between 2016 and 2035.

Location	Potential Well Spuds ('16-'35)	Mineral Ownership	Mineral Estate Acres	Current Wells	Undeveloped Acreage	Acreage Ratio	Potential Future Wells
Above the Rim	1650	Federal	34,990	0	34,990	65%	1,070
		Fee	19,640	82	18,820	35%	580
Below the Rim	3820	Federal	38,740	890	29,840	64%	2,450
		Fee	33,630	1,689	16,740	36%	1,370
Total Federal	-	Federal	73,730	890	64,830	-	3,520
Total	5470	-	127,000	2,661	100,390	-	5,470

Based on the undeveloped acreage, 3,520 potential wells could be drilled into the federal mineral estate between 2016 and 2035: 1,070 wells into the federal minerals above the rim and 2,450 wells into the federal minerals below the rim.

Reserves

Estimated ultimate recovery (EUR) is the total volume of gas that can reasonably be extracted from a well or a reserve. This RFD evaluates the possible reserves to be recovered in the 20-year planning horizon from the two proven formations: the Mesaverde and the Wasatch formations.

Based on Figure 11, a typical well drilled into the Mesaverde Formation in the RPPA could produce approximately 1.35 BCF over its life. The EUR for the existing 2,600 producing Mesaverde wells is approximately 3.5 TCF. The EUR for the 5,470 potential future wells is 7.4 TCF. Therefore, the total EUR for this RFD of 10.9 TCF for existing wells and potential wells for Mesaverde production is approximately 63% of the 17.1 TCF of the EUR within Mesaverde Formation inside the RPPA boundary.

Based on Figure 14, wells drilled into the Wasatch Formation could produce 0.74 BCF over the well's life. Due to the increased production from Mesaverde wells, none of the wells in the next 20 years are expected to be Wasatch wells. The EUR for the existing 90 Wasatch wells is 65 BCF. This is approximately 11% of the 0.6 TCF estimated to exist within the Wasatch Formation inside the RPPA. Refer to Table 4 for the total EUR in each area of the RPPA and the potential recovered by the current and future wells.

Table 4. Summary of EUR for current and potential future wells.

Formation	Location	Mineral Ownership	Mineral Estate Acres	Reserve EUR (BCF)	Current Wells	Potential Future Wells	EUR for Current and Future Wells (BCF)	Percent Depleted
Wasatch	Above the Rim	Federal	34,990	160	0	0	0	0%
		Fee	19,640	90	5	0	5	6%
	Below the Rim	Federal	38,740	180	30	0	20	11%
		Fee	33,630	155	55	0	40	26%
	Wasatch Total		127,000	585	90	0	65	11%
Mesaverde	Above the Rim	Federal	34,990	4,725	0	1,070	1,445	31%
		Fee	19,640	2,650	77	580	885	33%
	Below the Rim	Federal	38,740	5,230	860	2,450	4,470	85%
		Fee	33,630	4,540	1,634	1,370	4,055	89%
	Mesaverde Total		127,000	17,145	2,571	5,470	10,855	63%
Total Federal			73,730	10,295	890	3,520	5,935	58%
Total			127,000	17,730	2,661	5,470	10,920	62%

Wells drilled into the Mancos Formation were not included in the estimate of future production. Currently the Mancos Formation is still in the exploratory stage of its development in the RPPA and the potential Mancos reserves cannot be accurately determined. For purposes of predicting the EUR for the RPPA in Table 4, all of the potential 5,470 wells were considered Mesaverde wells. This will probably not be the case. Likely, a percentage of the potential 5,470 well number would be wells drilled into the Mancos Formation. However, there is not enough data on the Mancos/Niobrara shale wells to determine reasonable estimates on the amount of development that might occur in the RPPA. In addition, appropriate well spacing is undetermined, which is a critical aspect in determining the development required to extract the resource. The BLM anticipates increased Mancos/Niobrara exploration but cannot reasonably estimate potential future development, in contrast to Mesaverde development for which there are clear trends. The RFD assumes that the increased development in the Mancos formation would be offset by decreased development in the Mesaverde formation.

The mineral reserves underlying the RPPA contain an estimated 17.7 TCF of gas within the Wasatch and Mesaverde Formation. Combining the EUR in the Wasatch and Mesaverde formation, the current wells and potential wells that could be drilled in the next 20 years could drain around 62% of the EUR for the RPPA.

Leased Acreage

Based on the acreage and predicted gas prices, the 3,520 potential wells could be drilled on 73,730 acres of federal minerals in the next 20 years. On the 70,190-leased BLM acres, 890 wells have already been drilled into federal minerals. The combined well number of potential and pre-existing wells, 4,410 wells, could potentially drain 5.9 TCF. The EUR for the leased-federal minerals in the RPPA is 10.3 TCF. Combining the potential wells in the next 20 years and current wells, the RFD estimates 58% of the total wells needed to drain the leased acreage could be drilled. This is based on the expectation that development would occur on 10-acre spacing in the Mesaverde Formation and 160-acre spacing in the Wasatch Formation. More wells might be needed to drain Mancos Formations.

RFD Baseline Scenario Assumptions and Discussion

The baseline for projecting an accurate RFD for the life of the Resource Management Plan (RMP) is based on all potentially productive areas being open for leasing under the standard lease terms and conditions, except those areas designated as closed to leasing by law, regulation, or executive order. None of the federal minerals is currently closed to leasing, but 31 leases in the Roan Plateau Planning Area (RPPA) are suspended due to ongoing litigation. The RFD analyzed the federal minerals without regard to leased or unleased federal minerals and assumed all federal minerals within the RPPA were open to leasing. A summary of the current and future development is shown in Table 5.

Table 5. Summary of well spud potential.

Mineral Ownership & Location	Mineral Estate Acres	Leased Acres	Suspended Acres	Current Wells (9-2013)	Potential Future Wells	Percent of New Activity
Federal above the Rim	34,990	34,380	33,000	0	1,070	19.6%
Fee above the Rim	19,640	-	-	82	580	10.6%
Federal below the Rim	38,740	35,920	21,630	890	2,450	44.8%
Fee below the Rim	33,630	-	-	1,689	1,370	25.0%
Total Federal	73,730	70,190	54,630	890	3,520	64.4%
Total	127,000	-	-	2,661	5,470	100.0%

Oil and gas development is dependent on the operator's ability to profit from the development; therefore, the potential well numbers are tied to predictions in natural gas prices from NYMEX and the EIA. The reference predictions for the Henry Hub Spot Price were selected as the rationale price prediction to model future development in the RPPA. Other RFDs have based development on current rig activity or industry estimates. Rig activity and industry estimates are based on current gas prices; therefore, the gas price is the key independent variable for oil and gas development in the RPPA. Large changes from the predicted Henry Hub Spot natural gas price can increase or decrease the potential development. In addition, a change in drilling and completion technology may lower the cost of oil and gas development. This would allow operators to economically drill at lower natural gas prices and could increase the potential well numbers in the RFD. At this time, the well numbers for the next 20 years are the best estimate of development.

Surface Disturbance Due to Oil and Gas Activity on All Lands

It is estimated that 5,470 fee and Federal wells could be drilled over the next twenty years. This is an average of approximately 274 wells per year over the planned life of the RMPA. This is only an average, and it is more likely that an uneven distribution of wells could be drilled each year, depending on market forces, lands available for leasing, and political constraints. All wells are predicted to be gas wells (both coalbed natural gas and conventional natural gas), and many would have associated natural gas fluids (condensate) and, in some cases, produced water. However, over time and with an increase in exploring marginal USGS plays, some primary oil wells may also be developed. Tables 6 through 12 present estimates of current and future surface disturbance associated with well pads, access roads (including collocated pipelines, and central facilities. Data presented includes gross disturbance (including both temporary and long-term), reclamation (including both interim and final), and net disturbance (gross disturbance minus reclamation). Interim reclamation is conducted following completion of a wellpad and reduces the disturbed footprint to the amount needed for ongoing production and periodic workover operations. Final reclamation occurs after a pad no longer has producing wells.

Assumptions used in preparing Table 6 through Table 12 are based on BLM experience from historical exploration and development in the CRVFO and from Industry input and are as follows:

- Existing pads are assumed to average 5 wells per pad of gross disturbance.
- Plugged & Abandoned numbers are assumed to be one well per 3 acre pad.
- Plugged and abandoned reclamation assumes 75% reclaimed (pad and road), but final abandonment notice (FAN) not approved.
- Existing multi-well pads and future wells pad averaging 20 wells per pad are assumed to be 5 acres in size.
- Existing roads average .40 miles per pad for existing well pads. This number was derived by using a ratio of existing roads to existing well pads. Road acres per well pad are approximated from the following calculation. .40 x 5,280 feet x 75 feet (road width) ÷ 43,560 square feet per acre ≈ 3.6 acres of road per pad.
- It is assumed that the .40 average will apply to future road and well pad development. Therefore, approximately 117 miles out of 146 miles of existing BLM unimproved roads (not associated with oil and gas development) would be upgraded /improved in order to support future development. However, after interim reclamation (IR) the roads would be reduced by 67% (see below), which would ultimately result in no net gain.
- Central facilities are assumed to average 10 acres per facility. It is assumed that the number of central facilities would double over the life of the RPPA SEIS Revision. Since 36% of the projected wells are Federal, it is assumed that 36% of the central facilities would service Federal wells. The central facilities are expected to be developed on private land.
- Gross disturbance well numbers include wells of all status including producing, temporary abandoned, abandoned, service, and drilling.
- Treatment facility surface disturbance is included in the well pad figures.
- Pipelines, gathering lines, and power lines that are approved as a lease or unit action are included in this RFD surface disturbance acreage and are largely included in the access road corridor. Pipelines that require right-of-way approvals are realty actions not oil and gas operations; as a result are not included in this RFD.

- As a result of drilling multiple wells per pad, future well pads and access roads are assumed to not be affected if a well is plugged and abandoned or drilled and abandoned. Hence, future dry hole reclamation acreage is not considered.
- Interim reclamation assumes that 2.5 acres of the original 6 acres is reclaimed (42% reclamation factor) and that the access road right of way is reclaimed down to 25 feet from 75 feet (67% reclamation factor).
- Final abandonment assumes 100% reclamation and FAN approved. Abandoned Fee wells are assumed to be final abandoned

Table 6. Existing surface disturbance for federal wells.

Component	Gross Disturbance	Reclaimed to Date				Net Disturbance (Gross Disturbance - Reclaimed to Date)
		Plugged and Abandoned	Final Abandoned	Interim Reclamation	Total Reclamation	
No. Wells	882[1]	8	0	882	-	
No. Pads	186[2]	-	-	178[7]	-	
Acres of Disturbance						
Well Pads	1,092[3]	18[5]	0	445[8]	463	629
Access Roads	670[4]	19[6]	0	429[9]	449	221
Central Facilities	0	0	0	0	0	0
Total	1,762	37	0	874	912	850

Table 7. Existing surface disturbance for non-federal wells.

Component	Gross Disturbance	Reclaimed to Date				Net Disturbance (Gross Disturbance - Reclaimed to Date)
		Plugged and Abandoned	Final Abandoned	Interim Reclamation	Total Reclamation	
No. Wells	1,740[10]	39	0	1,740	-	
No. Pads	389[11]	39	-	350	-	
Acres of Disturbance						
Well Pads	2,217	88	0	875	963	1,254
Access Roads	1,400	94	0	844	938	462
Central Facilities	30[12]	0	0	0	0	30
Total	3,617	182	0	1,719	1,901	1,746

Table 8. Existing surface disturbance for all wells.

Component	Gross Disturbance	Reclaimed to Date				Net Disturbance (Gross Disturbance -
		Plugged and Abandoned	Final Abandoned	Interim Reclamation	Total Reclamation	

						Reclaimed to Date)
No. Wells	2,622	47	0	2,622	-	
No. Pads	575	47	-	524	-	
			Acres of Disturbance			
Well Pads	3,309	106	0	1,311	1,417	1,892
Access Roads	2,070	113	0	1,265	1,348	692
Central Facilities	30	0	0	0	0	30
Total	5,379	219	0	2,576	2,765	2,614

Table 9. Estimated future surface disturbance from BLM wells.

Component	Count	Acres per site	Gross Disturbance	Interim Reclamation	Net Disturbance (Gross-Interim)
Well Pads	176[13]	5	880[14]	440[16]	440
Access Roads	176	4	634[15]	425[17]	209
Central Facilities	0	0	0	0	0
Total	352	9	1,514	865	649

Table 10. Estimated future surface disturbance for all wells.

Component	Count	Acres per site	Gross Disturbance	Interim Reclamation	Net Disturbance (Gross-Interim)
Well Pads	274	5	1,368	684	684
Access Roads	274	4	985	660	325
Central Facilities	3	10	30	0	30
Total	550	19	2,382	1,343	1,039

Table 11. Combined existing and future net surface disturbance from BLM wells.

Component	Existing Net Disturbance	Future Net Disturbance	Total
Well Pads	629	440	1,069
Access Roads	221	209	430
Central Facilities	0	0	0
Total	850	649	1,499

Table 12. Combined existing and future net surface disturbance from all wells.

Component	Existing Net Disturbance	Future Net Disturbance	Total
Well Pads	1,883	684	2,567
Access Roads	683	325	1,008
Central Facilities	30	30	60
Total	2,596	1,039	3,635

[1] wells - P&A wells
[2] existing active pads + single P&A pads
[3] ((existing active pads - single P&A pads) x 6 acres/pad) + (single P&A pads x 3 acres/pad)
[4] (existing active pads + single 3 acre pads) x 3.6 acres of road/pad
[5] (single P&A pads x 3 acres/pad) x .75 reclamation factor
[6] (single P&A roads x 3.6 acres/road) x .67 reclamation factor
[7] existing active pads - single P&A pads
[8] existing active pads x 2.5 acres/pad
[9] (existing active pad roads x 3.6 acres/road) x .67 reclamation factor
[10] wells - P&A wells
[11] existing active pads + single P&A pads
[12] 3 existing central facilities x 10 acres/facility
[13] future wells ÷ 20 wells/pad
[14] future well pads x 5acres/pad
[15] future well pad roads x 3.6 acres/road
[16] existing active pads x 2.5 acres/pad
[17] (existing active pad roads x 3.6 acres/road) x .67 reclamation factor

Produced Water Disposal

Currently, the BLM surface lands do not have permitted surface discharge, only contained produced water disposal in approved pits or tanks or approved trucking of produced water to approved disposal facilities. Both the BLM and the State of Colorado have jurisdiction over surface discharge (retention ponds, skimmer pits and equipment, tanks, and any additional surface disturbance) and approves surface discharge permits. Operations from the point of origin to the point of discharge are under the jurisdiction of the BLM. Operations from the point of discharge downstream are under the jurisdiction of the State of Colorado. The State of Colorado approves the underground injection of water into the disposal wells. Water quality has to meet their minimum standards for fresh water (<3,500 mg/L TDS) before it is allowed to be surfaced discharged. Water quality within the CRVFO ranges in quality from potable to well over 25,000 mg/L of total dissolve solids (TDS). In the Rulison field, produced water from the Williams Fork Formation is around 3,000 mg/L TDS; in the Parachute field it is around 4,200 mg/L TDS; and in the Grand Valley field it is around 21,400 mg/L TDS. Typically the deeper the formation and the closer to the basin center, the poorer the quality of water. Formations in these areas usually contain connate water, marine in origin and very briny (>10,000 mg/L TDS). If the water is lacustrine or fluvial in origin, it is somewhat fresh (1,500 to 10,000 mg/L TDS). Shallow formations, formations near the basin margin recharge zones, and formations with conduits for fresh water recharge (i.e., faults) can contain very fresh to potable meteoric water (<1,500 mg/L TDS). Nearly 10 million barrels of water have been produced within the CRVFO. Much of the future produced water may come from fee CBM wells. Fortunately most of the gas wells in the CRVFO do not produce a lot of water. Other methods of water disposal used within the CRVFO are reinjection, disposal into evaporation pits, and trucking to approved disposal facilities.

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Appendix A: RPPA Maps

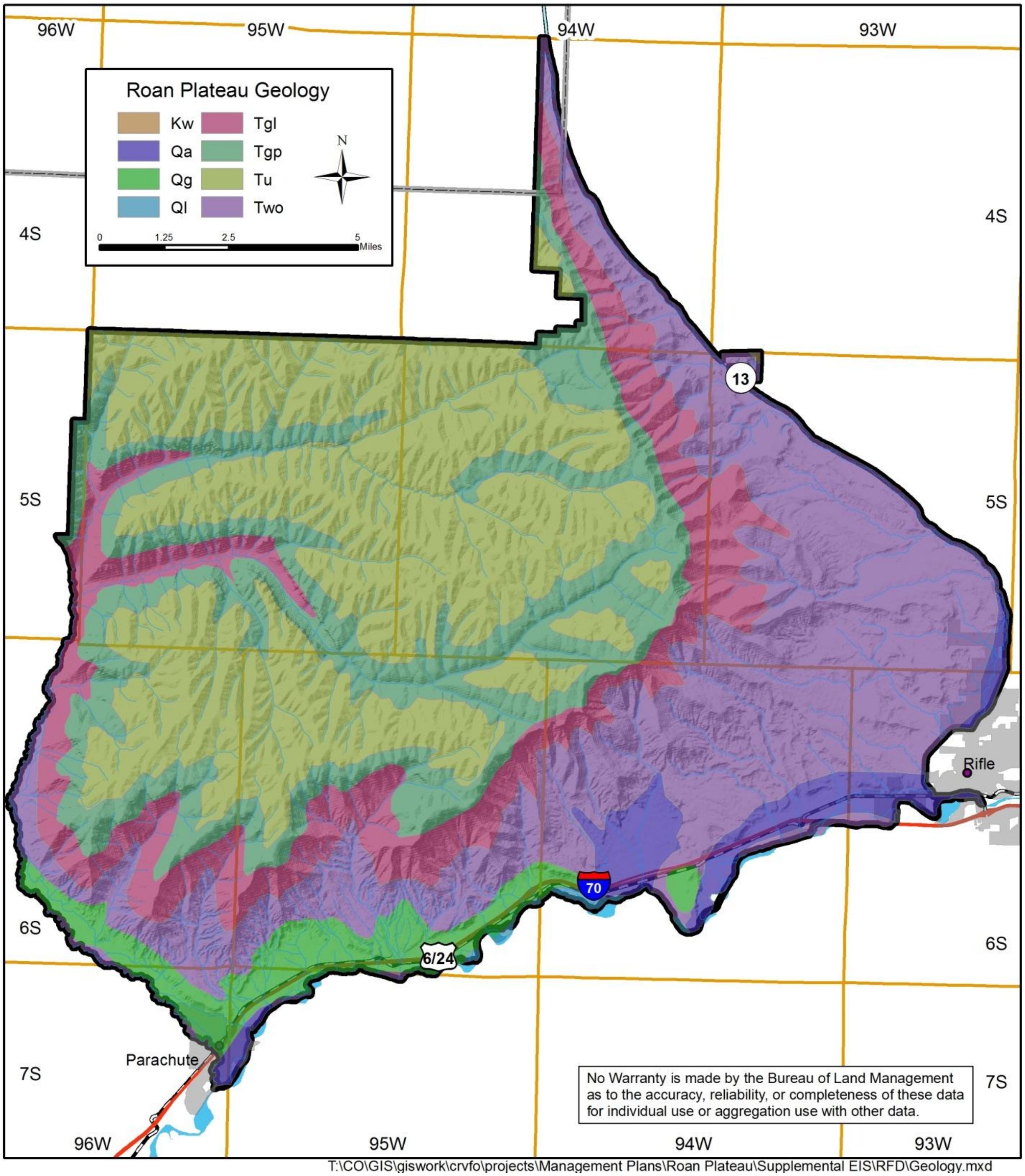

Figure 20. The geology in the RPPA.

Kw is the Williams Fork Member of the Mesaverde Formation, Tgi is the Jackrabbit Ridge member of the Green River Formation , Qa is Quaternary Alluvium Deposits, Tgp is the Parachute Creek member of the Green River Formation, Qg is Quaternary Gravel Deposits, Tu is the Uintah Formation, Ql is Quaternary Loess, and Two is the Shire member of the Wasatch Formation..

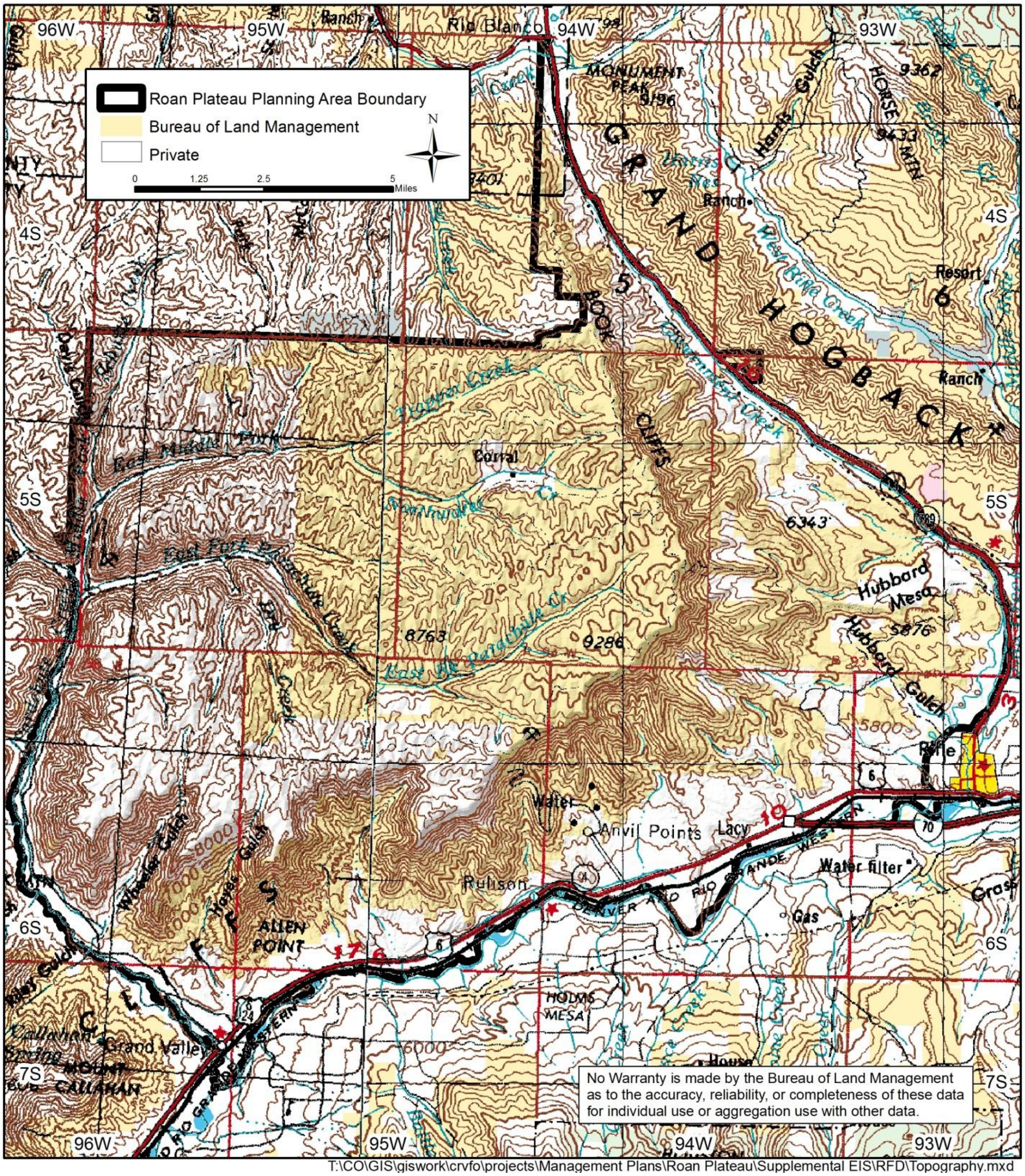

Figure 21. Topography in the RPPA.

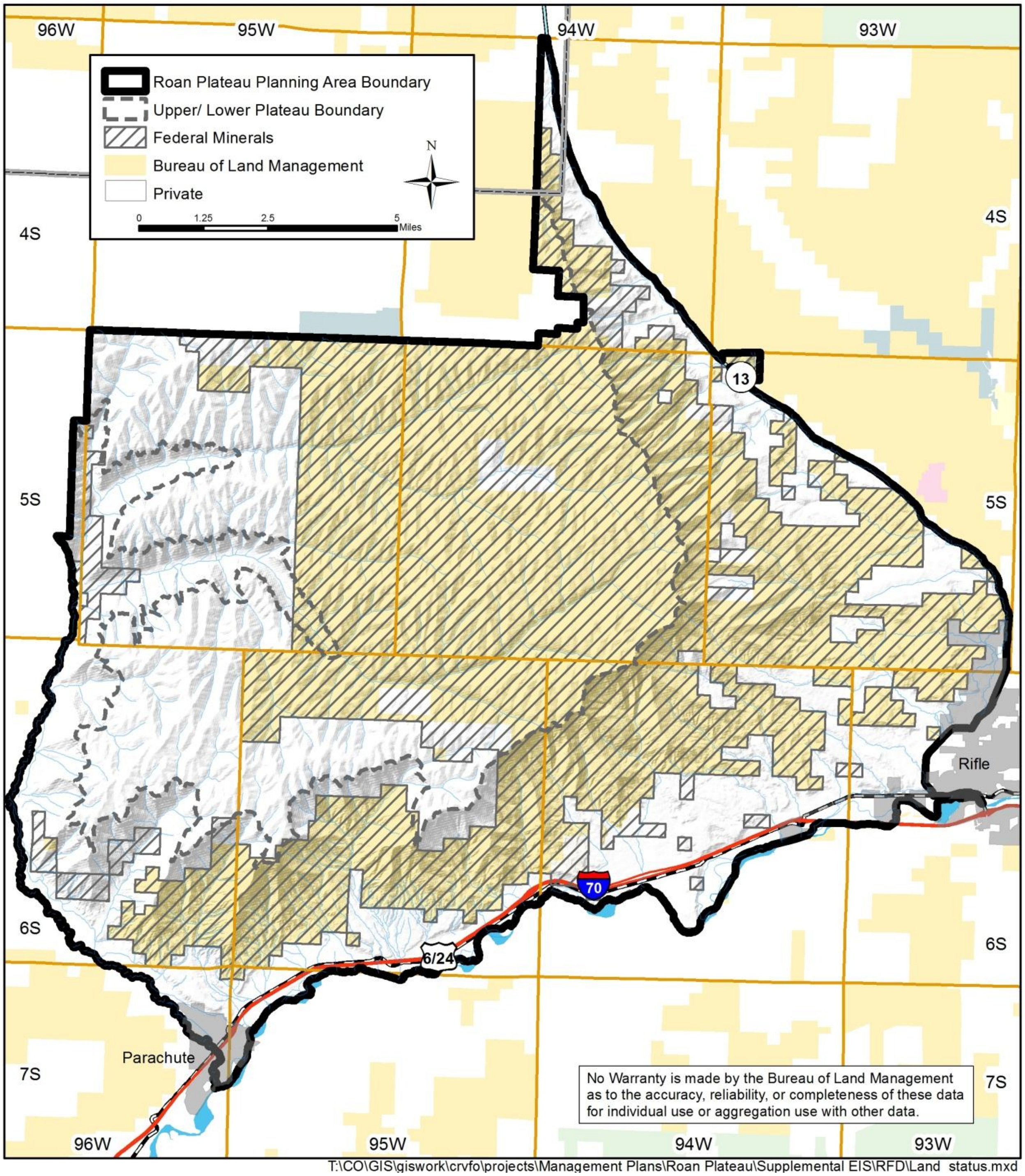

Figure 22. Federal minerals in the RPPA.

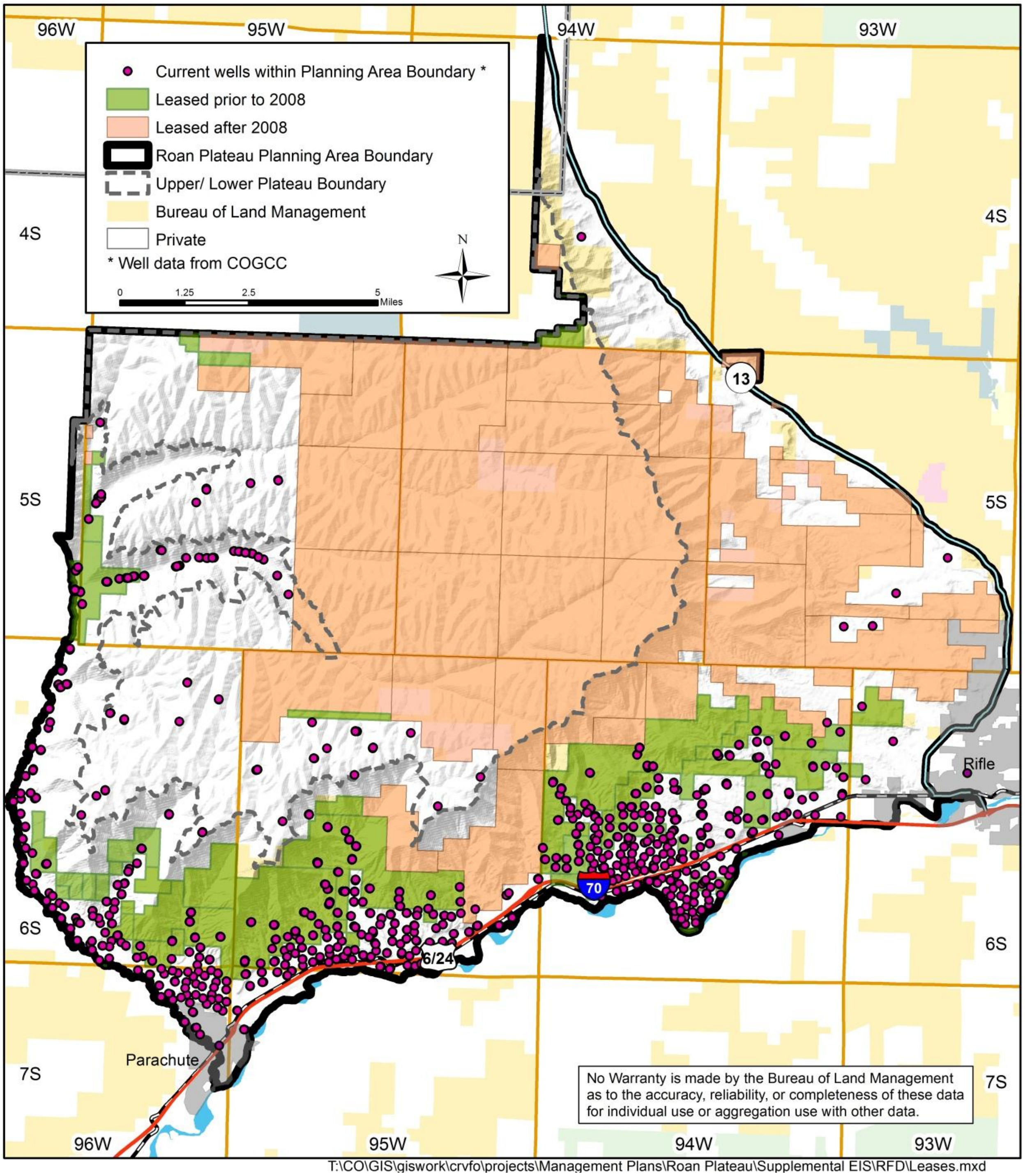

Figure 23. Leases and current well locations in the RPPA

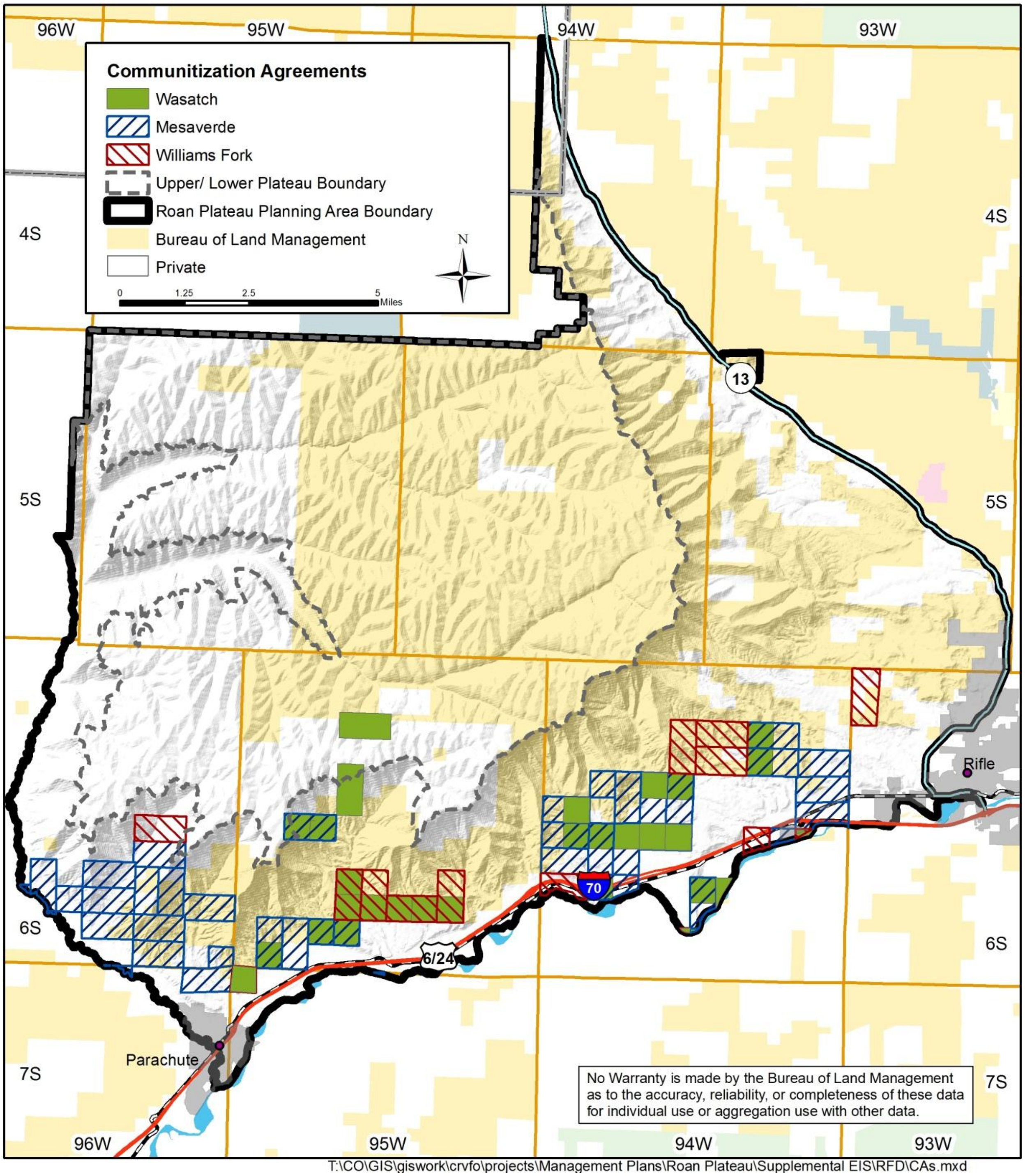

Figure 24. Current Communitization Agreements in the RPPA.

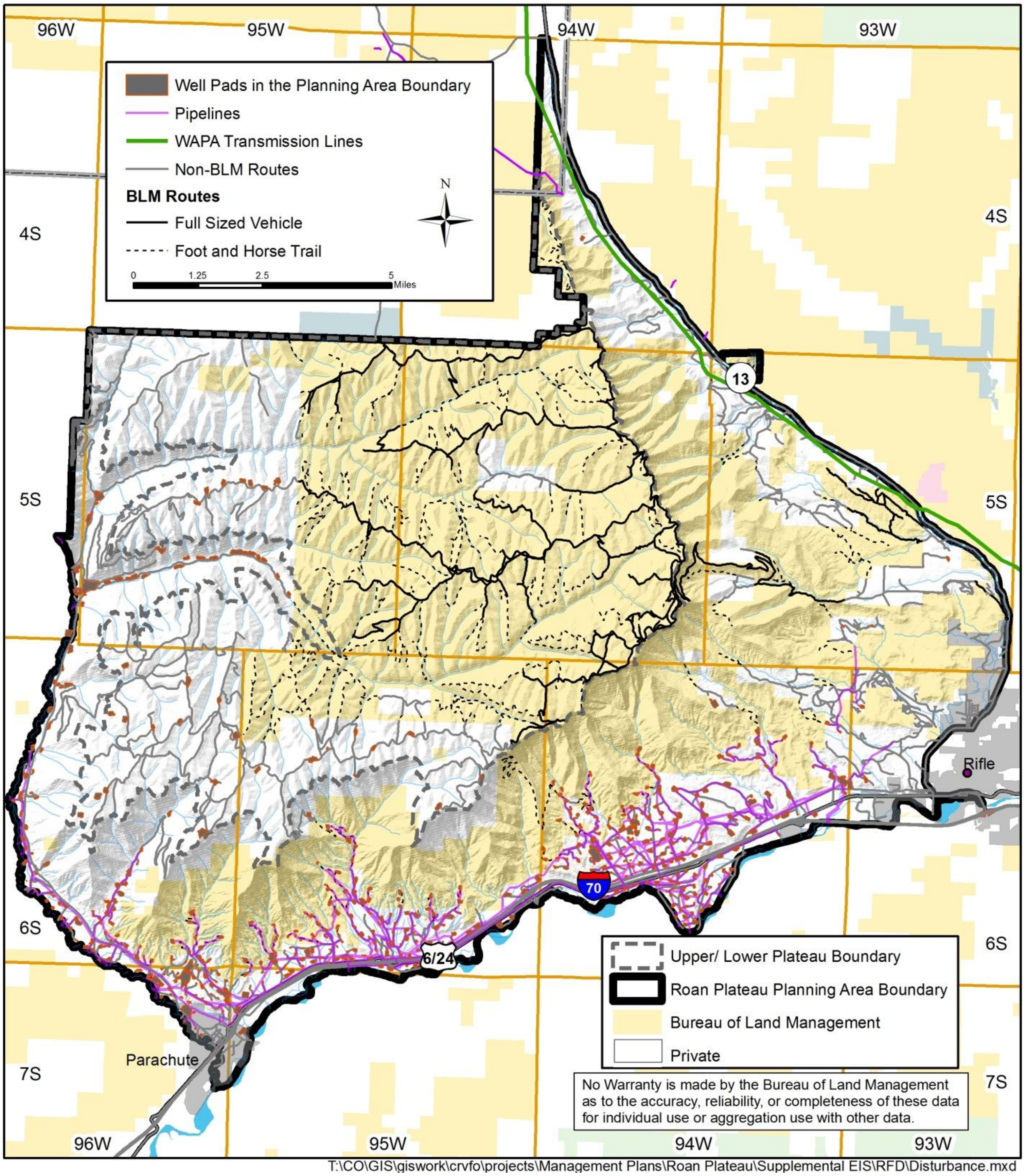

Figure 25. Current surface disturbance in the RPPA.

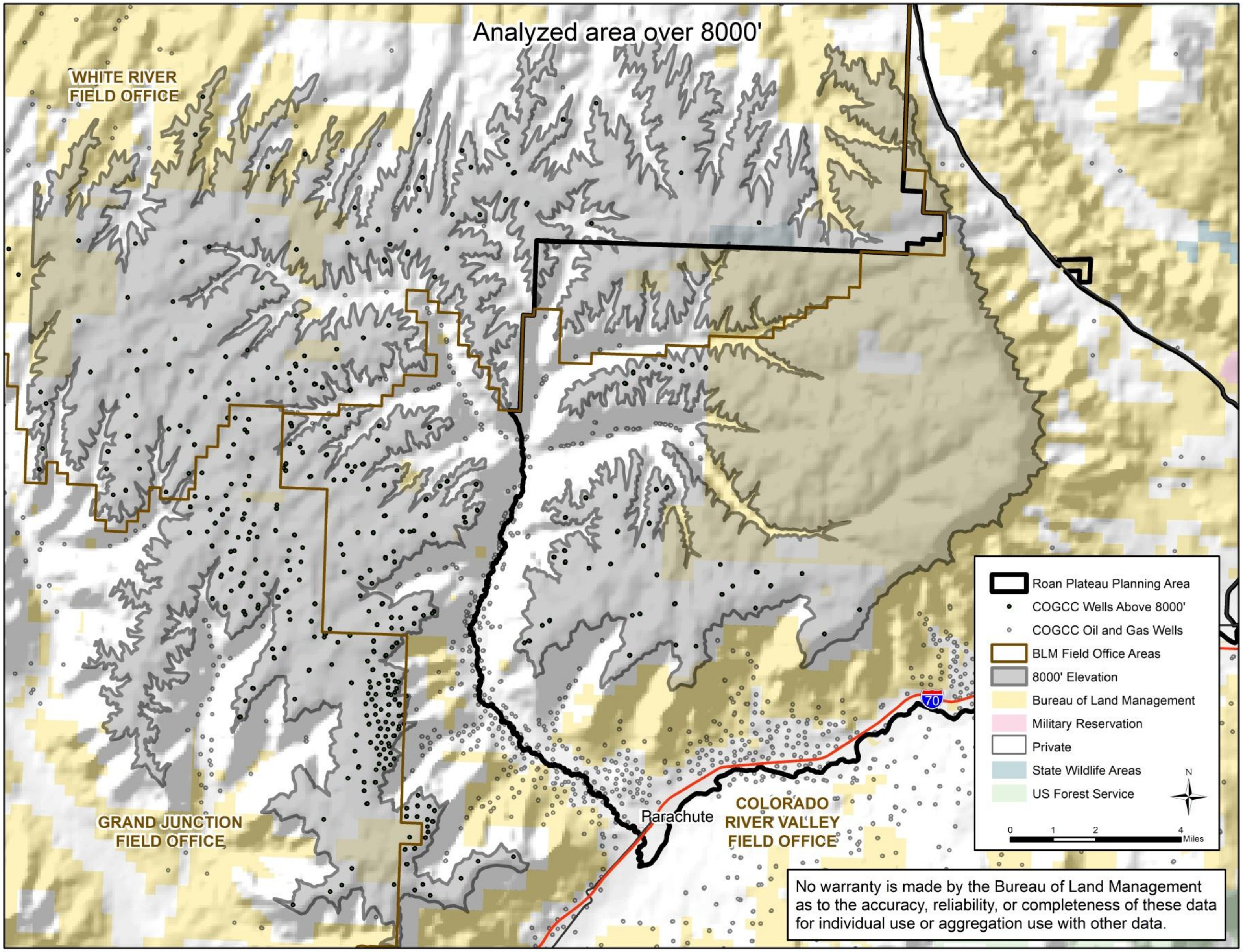

Figure 26. Wells pulled with similar activity as future development on the plateau in the RPPA.